COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 2004

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty-five years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at industry conferences on ratemaking, accounting, and tax issues.

I have testified before the Kentucky Public Service Commission on numerous occasions, including the two most recent Louisville Gas and Electric Company ("LG&E" or "Company") base rate cases, Case Nos. 90-158 and 98-474; the most recent Kentucky Utilities Company ("KU" or "Company") base rate case, 98-426; the merger proceeding, Case No. 97-300; numerous LG&E and KU environmental cost recovery ("ECR") and fuel adjustment clause ("FAC") proceedings, and proceedings involving Kentucky Power Company ("KPC" or "Company") and Big Rivers Electric Corporation. Most recently, I filed testimony before the Commission in the LG&E and KU Earnings Sharing Mechanism ("ESM") proceedings, Case Nos. 2003-00335 and 2003-00334, respectively. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. **On whose behalf are you testifying?**

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group a large users taking electric and gas service on the LG&E system.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to address the revenue requirement requests of LG&E for electric and gas service, to address the continuation or termination of the ESMs as an alternative form of regulation, and to address the change in base rates that should occur upon the expiration of the merger savings surcredit and the expiration of the VDT surcredit.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's requested electric and gas base rate increases for the issues listed and amounts quantified on the following tables. I address each of these issues, except for the return on common equity, which Mr. Baudino addresses, and quantify the effects of each issue on the revenue requirements.

Louisville Gas and Electric Company - Electric Only
Summary of KIUC Revenue Requirement Issues

Issues	$000
Operating Income Adjustments	
Unbilled Revenues	$1,867
O&M - Labor Savings VDT	$10,088
O&M - Pension and OPEB	$2,755
O&M - Amort of W/O Carbide Lime, Obsolete Inventory	$708
Depreciation - Gross Salvage and Cost of Removal	$3,881
Depreciation - Post Test Year Plant Additions	$3,441
Rate of Return Adjustments	
Return on Common Equity	$30,701
Additional Annualized Reduction	$53,441
LG&E Claimed Electric Revenue Deficiency	-$63,764
KIUC Adjusted Revenue Deficiency	-$10,323

Louisville Gas and Electric Company - Gas Only
Summary of KIUC Revenue Requirement Issues

Issues	$000
Operating Income Adjustments	
Unbilled Revenues	$2,780
O&M Labor Savings - VDT	$2,711
O&M - Pension and OPEB	$725
Depreciation - Gross Salvage and Cost of Removal	$571
Rate of Return Adjustments	
Return on Common Equity	$5,933
Additional Annualized Reduction	$12,720
LG&E Claimed Gas Revenue Deficiency	-$19,106
KIUC Adjusted Revenue Deficiency	-$6,386

I also recommend that the Company's ESM be discontinued. I recommend that the ESM surcharge based on the test year 2003 be discontinued on the effective date of any electric base rate increase authorized in this proceeding. The Commission should consider the ESM terminated by virtue of the Company's filing of its electric base rate increase request in December 2003.

The Commission should not allow two alternative and mutually exclusive forms of regulation to remain in effect simultaneously. The simultaneous operation of two ratemaking paradigms could not have been envisioned by the Commission when it offered the Company the choice of the ESM or continued traditional regulation in Case No. 98-474. It cannot possibly meet the statutory requirement for just and reasonable rates.

The simultaneous operation of two ratemaking paradigms will result in excessive rates through rate pancaking and the simultaneous imposition of two separate rate increases. Under both ratemaking paradigms, base rates are set prospectively. The ESM was not established as a historic test year true-up mechanism, despite the Company's position to the contrary.

If the Commission does not terminate the ESM surcharge upon the effective date of any rate increase from this proceeding, and continues the ESM, then the Commission should annualize the rate increase for the ESM 2004 test year in the same manner that it annualized the rate reduction for the ESM 2000 test year when it was initially implemented.

In addition, I recommend that the Commission specifically order in this proceeding that base rates be reduced by the amounts included in the revenue requirement for the merger savings surcredit upon its expiration in 2008 and for the VDT surcredit upon its expiration in 2006. Base rates pursuant to the ESM would have been adjusted annually to reflect the removal of these amounts; however, base rates determined in this proceeding will not be adjusted downward upon the expiration of these surcredit amounts unless the Commission specifically directs the Company to do so.

Finally, I recommend that the Commission adopt a System Sales Clause to share off-system sales margins between the Company and ratepayers patterned after the System Sales Clause currently in effect for Kentucky Power Company. The System Sales Clause would share 50% to the Company and 50% to the ratepayers the net change in off-system sales margins compared to the margin reflected in base rates.

II. REVENUE REQUIREMENT

Unbilled Revenues

Q. Please describe the Company's adjustments to remove unbilled revenues for ratemaking purposes.

A. The Company has reduced electric operating revenues by $1.867 million and gas operating revenues by $2.780 million to remove unbilled revenues for ratemaking purposes from its per books test year revenues. The Company's adjustments convert the Company's revenue accounting from the unbilled revenues methodology it actually uses for per books accounting purposes to a meters read methodology for ratemaking purposes.

Q. Please describe the difference between the unbilled revenues and meters read methodologies for recognizing revenues.

A. The Company recognizes actual revenues on its accounting books based upon the unbilled revenues methodology. The unbilled revenues methodology matches the revenues in the month with the service provided and the costs incurred to provide that service. The unbilled revenues methodology adjusts the billed revenues in the month to properly recognize the revenues actually earned in the month based on the electricity delivered. It removes the effects on revenues of delays in meter reading and billing due to the fact that all meters are not read and bills issued on the last day of the month in which the service was provided. Each month, the Company quantifies and accrues the unbilled revenues for that month and reverses the accrual for the preceding month. The reason the accrual for the preceding month is reversed is that the preceding month unbilled revenues actually are billed in the current month. Unbilled revenues may be positive or negative.

In contrast to the unbilled revenues methodology, the meters read methodology recognizes revenues on a lagged basis only after meters are read and bills are issued. There is no match in any given month between the revenues recognized and the service provided because a portion of the billings in the month are due to service provided in the preceding month and do not include billings for all the service provided in the current month.

Q. Has the Commission previously addressed the issue of whether the Company's revenues should be adjusted from the unbilled revenues methodology actually used by the Company to the meters read methodology for ratemaking purposes?

A. No. The Commission has not specifically addressed the issue of whether the Company should be allowed to restate its revenues for ratemaking purposes to a methodology the Company abandoned for accounting purposes more than a decade ago, although the Company previously has reflected such adjustments in its rate filings. In Case No. 90-158, the Commission addressed only the issue of the one-time gain that resulted from the Company's conversion from the meters read methodology to the unbilled revenues methodology during the test year. The parties did not litigate nor did the Commission address whether the Company should be allowed to restate its accounting revenues for ratemaking purposes using the meters read methodology.

Q. Should the Commission accept the Company's adjustment to restate its per books accounting revenues to utilize the meters read methodology?

A. No. There is no principled basis to accept this adjustment. First, the adjustment does not comport with reality. Second, it creates an inappropriate difference between the revenues for ratemaking and accounting. Third, it creates a ratemaking mismatch between the revenues that should be and actually were recognized compared to the service and costs to provide that service actually incurred during the test year.

<u>Operation and Maintenance Expense – Failure to Achieve Labor Savings from VDT</u>

Q. **Please describe the premise underlying the incurrence by the Company of $144.385 million in severance costs related to its workforce reduction program initiated in the first quarter 2001.**

A. The premise underlying the incurrence of this huge cost was that the Company would achieve savings by reducing the number of employees. Some positions were to be eliminated permanently, some were to be filled with lower cost employees, and some were to be eliminated permanently but effectively filled through the use of contractors. The Company projected that savings over five years would exceed the costs of the employee buyout.

Q. **Please describe the ratemaking treatment of the employee buyout costs and the projected savings.**

A. In Case No. 2001-169, the Company sought to defer the entirety of the employee buyout costs and to amortize the deferred debits as an expense recoverable through its annual Earnings Sharing Mechanism filings. Pursuant to a settlement of the ratemaking treatment of these costs and savings, along with other issues in other proceedings, the

Company was allowed to defer the employee buyout costs and amortize them over five years. The Company agreed to provide 50% of the projected savings to ratepayers through a value delivery ("VDT") surcredit. In addition, the Company was allowed to include 50% of the projected savings as an expense in its annual ESM filings in 2001 and 2002 and in any "successor earnings sharing ratemaking mechanism."

Q. What was the effect of this ratemaking treatment in the ESM proceedings?

A. In 2002 and 2003, the Company was below the lower threshold of the ESM return on equity deadband. As such, it was or will be able to recover from ratepayers at least 40% of the VDT amortization expense, at least 40% of the savings amounts that were flowed through the VDT surcredit, and at least 40% of the retained savings it included as an expense.

Q. How has the Company reflected this ratemaking treatment in its filing in this proceeding and what is the effect?

A. The Company has included the entirety of the VDT amortization expense, 100% of the savings amounts that were flowed through the VDT surcredit, and 100% of the retained savings as an expense adjustment, which it has included as Adjustment 23, reflected on

Rives Exhibit 1 Reference Schedule 1.20. The Company has included \$23.900 million (electric) and \$6.100 million (gas) for the VDT amortization, \$3.760 million (electric) and \$1.010 million (gas) for the VDT surcredit, and \$5.640 million (electric) and \$1.515 million (gas) for the retained savings as an expense adjustment. In total, the Company has included \$33.300 million (electric) and \$8.625 million (gas) for the workforce reduction costs in its revenue requirement.

Q. **What labor savings amounts actually were reflected in the Company's filing compared to the costs it incurred in 2000, the year prior to the implementation of the VDT?**

A. The Company claims that it is unable to quantify the labor savings. However, it was able to quantify its direct labor costs in total and separated between expense and capital in response to PSC 1-23(c). In the test year, its total direct labor, including the costs charged from Servco, the LG&E Energy mutual services company, was \$84.834 million. In 2000, the year prior to the workforce reduction program, its total direct labor was \$104.959 million. The comparable expense amount for the test year was \$74.664 million and for 2000 was \$86.240 million. In other words, the actual direct labor savings were only \$18.719 million in total, of which \$11.576 million was expense. I have replicated the Company's response to PSC 1-23(c) as my Exhibit___(LK-2).

Q. How do the actual labor cost savings in the test year from 2000 compare to the costs of the workforce reduction included in the revenue requirement?

A. The savings in total represent only 45% of the workforce reduction costs included by the Company in this proceeding. The expense portion of the savings represents only 28% of the workforce reduction costs included in the revenue requirement by the Company in this proceeding.

Q. Does this comparison include all the costs that have been incurred in the test year compared to the year before the workforce reduction?

A. No. It does not include any increases in contractor costs incurred by the Company due to reductions in employees. In addition, it does not include the related costs of pensions, other postretirement benefits, or any other overhead costs, all of which would have or should have been lower if indeed the Company had reduced its direct labor costs to the levels used to justify the VDT deferral and amortization.

Q. Do you recommend that the Commission disallow a portion of the O&M expense due to the Company's failure actually to achieve savings that equaled or exceeded the cost of the employee buyout?

A. Yes. I recommend that the Commission disallow at least 50% of the net harm to ratepayers from the Company's failure to achieve these labor savings. The disallowance at 50% is $12.790 million in total, with $10.088 million to electric and $2.711 million to gas using the same percentage allocations between electric and gas used for the VDT surcredit. I have computed the net harm to ratepayers as $25.579 million, consisting of the total $41.925 million included in the filing to recover these costs less the $4.770 million (electric and gas) returned to ratepayers through the VDT surcredit, and less the $11.576 million in direct labor expense savings reflected in the filing.

The Commission has an obligation to ensure that rates are just and reasonable. It is not just and reasonable for ratepayers to bear the burden not only of the costs of the workforce reduction, but also the imputed savings retained by shareholders, the sum of which are substantially in excess of the direct labor savings actually achieved. It would be reasonable for the Commission to disallow the entirety of the workforce reduction costs included that exceed the direct labor achieved savings.

Post Test Year Adjustment to Increase Pension and Post Retirement Benefit Expense

Q. Please describe the Company's request to increase pension and post-retirement benefit expense.

A. The Company proposes a selective post test year adjustment to increase its pension and post-retirement benefit expense to projected 2004 levels. These projections are preliminary estimates based upon computations provided by Mercer prior to the filing of the Company's case. However, the actual pension and postretirement benefit expense booked in 2004 will be based, in part, upon actual December 31, 2003 plan assets and obligations, which were not available and therefore, could not be known and measurable at the date the Company prepared its rate case filing, let alone at the date it was actually filed.

Q. Please describe the basis for your conclusion that the projections relied upon by the Company were preliminary estimates and are not known and measurable at the date the Company prepared its rate case filing.

A. The Company's proforma adjustment relies upon certain "disclosure statements," which Mercer prepared prior to December 31, 2003. The Company has not yet received an actuarial study from Mercer for 2004, according to its responses to PSC 2-16(e) and KIUC 1-88. Indeed, Mercer could not have prepared or released such an actuarial study because actual December 31, 2003 information was not yet available for that purpose. Thus, the disclosure statements, of necessity, were predicated upon estimates in lieu of actual amounts for the December 31, 2003 valuations. The actual December 31, 2003 valuation ultimately will be determined by Mercer to compute the Company's 2004 pension and postretirement benefit expense, not the estimates it prepared based on December 31, 2003 projections for the Company's rate case filing. It isn't at all clear what assumptions Mercer made on behalf of the Company to project the December 31, 2003 valuations for this purpose. Nevertheless, it is clear that the Company will book its 2004 pension and post retirement benefit expense based upon actual December 31, 2003 valuations, not the estimates prepared by Mercer for use by the Company in its rate case filing.

The Company was asked to provide the actuarial report relied on for its adjustment in PSC 2-16(e) and KIUC 1-88. The Company's response to PSC 2-16(e) stated "Please see that attached actuarial reports from Mercer for the fiscal year ending December 31, 2002. The actuarial reports from Mercer for the fiscal year ending December 31, 2003 are not yet available." However, that representation is not correct. A reading of the titles of the actuarial reports provided by the Company in that response indicate that these were the actuarial reports relied upon for the Company's pension and postretirement benefit expense actually booked in calendar year 2003. The titles of the actuarial reports for LG&E are as follows, with all indicating that they are for the year 2003, not 2002:

- LG&E Energy Corp. Retirement Plan; Revised Actuarial Valuation Report As of January 1, 2003 for the Plan Year and Taxable Year Ending December 31, 2003 Including FAS 87 Expense for the Fiscal Year Ending December 31, 2003 (dated October 2003).

- Louisville Gas and Electric Company Bargaining Employees' Retirement Plan; Actuarial Valuation Report As of January 1, 2003 for the Plan Year and Taxable Year Ending December 31, 2003 Including FAS 87 Expense for the Fiscal Year Ending December 31, 2003 (dated September 2003).

- LG&E Energy Corp. Postretirement Benefit Valuation Report Under FAS 106; Expense for the Fiscal Year Ending December 31, 2003 (dated December 2003).

Q. Should the Commission accept the Company's proforma adjustment to increase pension and postretirement benefit expense?

A. No. First, this adjustment represents a selective post test year adjustment to increase the Company's revenue requirement. As such, it is one-sided and inequitable. It violates the test year principle of consistent quantification of all components of the revenue requirement. If the Commission accepts this post test year adjustment, then it should also make other post test year adjustments. For example, it could increase revenues to reflect expected customer growth in 2004. It could project increased off-system sales revenues due to the significant capacity additions when the Trimble County gas turbines commence operation in 2004. It could project reduced O&M expense due to the substantial nationwide increases in productivity that exceed inflation as measured by the Bureau of Labor Statistics.

Second, the estimates relied on by the Company are not known and measurable. They do not reflect actual valuations as of December 31, 2003, consistent with the manner in which the Company relied on the Mercer actuarial reports for 2003. Third, they are estimates that cannot be verified based on the schedules provided in response to discovery.

Nonrecurring Expenses and Credits

Q. Please describe the adjustments the Company made to defer and amortize nonrecurring expenses for the writeoffs of carbide lime and obsolete inventory rather than removing the expenses altogether.

A. The Company reduced expense by $1.417 million to reflect a three year amortization of a writeoff of carbide lime included in test year O&M expense rather than by $2.125 million to remove the nonrecurring writeoff altogether, thus including $0.708 million in amortization expense in the revenue requirement for this cost. Similarly, the Company reduced expense by $.374 million to reflect a three year amortization of a writeoff of obsolete inventory included in test year O&M expense rather than by $2.060 million to remove the nonrecurring writeoff altogether, thus including $0.687 million in amortization expense in the revenue requirement for this cost.

Q. Should the Commission allow the Company to defer and amortize these amounts?

A. No. These nonrecurring amounts were subject to the ESM for the 2003 test year. As such, it is appropriate to remove these nonrecurring amounts to set base rates prospectively. It would be inappropriate to allow the Company to recover these costs through the ESM surcharge and also through base rates set in this proceeding.

Q. Please describe the adjustments the Company made to remove nonrecurring expenses credits for the LG&E corporate office lease expense and the Cane Run insurance recovery.

A. The Company increased test year expense by $2.276 million ($1.798 million electric and $0.478 million gas) to remove an expense credit for the renegotiation of the LG&E office building lease. This adjustment is detailed on Rives Exhibit 1 Reference Schedule 1.29. The Company also increased test year expense by $3.588 million (electric only) to remove insurance recovery for repairs on Cane Run that were expensed prior to the test year. The Company proposed no deferrals and no amortizations of these amounts.

Q. Should the Commission require the Company to defer and amortize these amounts?

A. No. These nonrecurring amounts were subject to the ESM for the 2003 test year. As such, it is appropriate to remove these nonrecurring amounts to set base rates prospectively.

However, if the Commission accepts LG&E's proposal to defer and amortize the writeoffs of carbide lime and obsolete inventory or KU's proposal to defer and amortize ice storm costs, all of which also are nonrecurring and subject to the ESM for the 2003 test year, then the Commission should require LG&E to defer and amortize these two amounts over a three year period and reduce the revenue requirement accordingly. The first adjustment would be to reduce electric operating expense, and thus the revenue requirement, by $0.599 million and gas operating expense by $0.159 million for the amortization of the expense credit due to the renegotiation of the LG&E office building lease. The second adjustment would be to reduce electric operating expense, and thus the revenue requirement, by $1.196 million.

Depreciation Expense – Gross Salvage and Cost of Removal

Q. Please describe how net salvage on interim retirements is reflected in the Company's proposed depreciation rates.

A. The Company includes net salvage on interim retirements as an increase to its proposed depreciation rates if the property grouping has projected net negative salvage (cost of removal exceeds gross salvage proceeds) and as a reduction to its proposed depreciation rates if the property grouping has projected net salvage (gross salvage proceeds exceed cost of removal).

In its depreciation study, the Company multiplies the net negative salvage rate against the interim retirement rate to determine the estimated net future salvage on estimated interim retirements. The Company then adds the estimated net future salvage on estimated interim retirements to the estimated net terminal salvage in order to compute the total net salvage rate. These computations are detailed on Table 2-a in Section 2 of the AUS depreciation study. I have replicated Table 2-a as my Exhibit___(LK-3).

The total net salvage rates from Table 2-a are multiplied by the original plant in service amounts to compute the net salvage dollars for each property grouping. The net salvage dollars are in turn added to the original plant in service amounts to compute the depreciation expense and depreciation rate based on the average remaining life for the property grouping. These latter computations are detailed on Table 2 in Section 2 of the AUS depreciation study. I have replicated Table 2 as my Exhibit___(LK-4) for electric and Exhibit___(LK-5) for gas.

Q. Please describe the methodology utilized by the Company to compute the net salvage on interim retirements included in its proposed depreciation rates.

A. The AUS depreciation study analyzed historic gross salvage and historic cost of removal by FERC plant account. The AUS analyses are detailed in Section 7 of the study and were performed by FERC plant account based upon actual historic data from the Company's property accounting records.

For gross salvage, the AUS depreciation study computed 3 year rolling bands, and from that data, computed the average actual historic gross salvage rate, and computed a 20 year trend rate, a 15 year trend rate, a 10 year trend rate, and a 5 year trend rate. In lieu of the average actual historic gross salvage rate, the AUS depreciation study then simply utilized the 5 year trend rate as the gross salvage rate against which it would net the proposed cost of removal rate. For every FERC plant account, the 5 year trend rate was lower than the actual historic data and was the lowest of the 20 year, 15 year, 10 year, and 5 year trend rates. For many FERC plant accounts, including the largest production accounts, the gross salvage rate derived by AUS using this methodology actually is negative, meaning that gross salvage actually is represented in the proposed depreciation rates as an additional cost of removal.

For cost of removal, the AUS depreciation study utilized the average of the actual data for the 20 year period, but then escalated the historic average to the midpoint of the average remaining service life by a projected annual inflation factor of 2.75%. This methodology had the effect of significantly increasing the cost of removal, and thus, the depreciation rates, for most property groupings. For some FERC plant accounts, the cost of removal rate was increased by several fold compared to the actual historic data for cost of removal.

Q. **Should the Commission utilize the 5 year trend for gross salvage on interim retirements?**

A. No. The Commission should utilize the average of the actual historic data. First, the actual data correctly establishes the relationship between gross salvage and interim retirements. There is no reason to assume that this known and measurable relationship will change in the future.

Second, the depreciation study substitutes a percentage trend for the actual gross salvage rate. Aside from the fact that the study utilizes the lowest percentage trend for the gross salvage rate, a problem in and of itself, a trend is itself meaningless and inappropriate to apply to estimated interim retirements.

Third, the Company's methodology results in negative gross salvage rates for all steam production FERC plant accounts except for account 312. This is an absurd result and should be rejected.

Q. **Should the Commission adjust the actual historic cost of removal rate for projected inflation?**

A. No. The Commission should utilize the average of the historic data. The historic data already reflects labor escalation in the year of the interim retirement compared to the vintage original plant cost of the retirement. As such, in future years, the same relationship is likely to hold as older vintage plant is retired. The Company has offered no evidence to demonstrate that the historic relationship will not hold prospectively.

The only rationale offered by the Company for this inflation factor is that labor costs will increase in the future. Yet inflation in labor costs already is reflected in the historic cost of removal compared to the older vintage plant that was retired. In the past, the labor costs included in the historic cost of removal also have increased due to inflation. The AUS study utilizes the current cost of removal in those historic years divided by the older vintage plant dollars that were retired in order to compute the cost of removal percentage for that year. As such, the effects of inflation already are reflected in the actual historic data. The Company's proposal to further increase the cost of removal double counts the effects of inflation by adding more inflation to the inflation already reflected in the actual historic data. The Commission should reject this methodology.

In addition, the Company's application of an inflation rate to the historic cost of removal represents a significant post test year adjustment, reaching forward many years into the future based on the average remaining service life of the property grouping. As I subsequently discuss in conjunction with the Company's inclusion of post test year NOx compliance plant additions, the Commission in the past has rejected attempts to include post test year costs on a selective basis such as this. The Commission should reject this methodology.

Q. Have you quantified the effects on the depreciation rates and the resulting depreciation expense of using the actual historic gross salvage and cost of removal rates on interim retirements (for electric production) and retirements (for electric non-production plant accounts, common, and gas)?

A. Yes. The effect on the depreciation rates and on test year depreciation expense is summarized on my Exhibit___(LK-6). For electric production, I first corrected the net salvage rates for interim retirements on the spreadsheet underlying Table 2-a. I used the resulting interim retirement percentages from the corrected Table 2-a in the spreadsheet underlying Table 2 to recompute the depreciation rates by FERC production plant account. In the next step of the computation, I used another spreadsheet provided by the Company to recompute the depreciation rates by production plant location using the recomputed depreciation rates for the production FERC plant accounts. To correct the net salvage rates on the spreadsheet underlying Table 2-a, I simply used the FERC plant account historic net salvage rates from Section 7 of the depreciation study. In the final step, I computed annualized depreciation expense and the proforma depreciation expense adjustment utilizing the spreadsheet provided by the Company for its Adjustment 1.11, substituting the corrected electric depreciation rates with the net salvage rates properly computed for the Company's proposed depreciation rates.

For electric nonproduction plant, common, and gas depreciation rates, I utilized the depreciation rates provided by the Company in response to PSC 2-24(b), which recomputed the depreciation rates using the FERC plant historic net salvage rates from Section 7 of the depreciation study. To compute annualized depreciation expense and the proforma depreciation expense adjustment, I utilized the spreadsheet provided by the Company for its Adjustment 14, Rives Exhibit 1 Reference Schedule 1.11, substituting the corrected common and gas plant depreciation rates reflecting the actual historic net salvage rates for the Company's proposed rates.

Q. The effect on the depreciation rates reflected on your Exhibit___(LK-6) for electric production plant does not agree with the effect quantified by the Company in response to PSC 2-24(b). Please explain why.

A. The effects quantified by the Company for electric production plant are erroneous. Removing the inflation factor from the cost of removal as requested by the Staff should have resulted in lower net negative salvage for certain production FERC plant accounts, and thus, lower depreciation rates for those plant accounts. Instead, the depreciation rates increased for those accounts. The error appears to be due a change in methodology compared to the depreciation study itself. In the response, the Company applied the actual net salvage rate percentages to the original cost of the assets rather than the interim retirements as it did in the AUS depreciation study. This methodological error in the response to PSC 2-24(b) had the effect of improperly increasing the net salvage reflected in the resulting depreciation rates.

<u>Depreciation Expense – Post Test Year Plant Additions</u>

Q. Did the Company reflect future plant additions in its proposed electric depreciation rates?

A. Yes. The Company included plant additions for NOx emission compliance that it projects for the years 2004-2006. The inclusion of these projected plant additions has the effect of significantly increasing the Company's proposed depreciation rates for FERC plant account 312, the FERC plant account with the largest proposed increase in depreciation rate.

Q. Should the Commission reflect future plant additions in depreciation rates?

A. No. These plant additions represent post test year adjustments and should not be reflected in the depreciation rates and depreciation expense included in the historic test year. These post test year adjustments violate the test year principle of consistency among all revenue requirement components. It is inequitable to selectively include projected post-test year cost increases without updating all revenue requirement components, including post-test year cost reductions and revenue increases that would reduce the revenue requirement.

The Commission previously has addressed this very issue of post test year additions and their inclusion in rate base and depreciation expense. In Case No. 90-158, the Commission rejected LG&E's request to include post test year Trimble County plant additions in the revenue requirement. It stated in that Order that "The Commission cannot and will not include in rate base the post test-period plant additions for Trimble County or the related first year depreciation expense. To do otherwise would disregard established, and we feel fair, just and reasonable rate-making practices enunciated and adopted in prior Commission decisions concerning post test-period plant additions."

In addition, the costs to reduce NOx emissions are recoverable by the Company through the ECR surcharge mechanism. Some or all of these projected NOx compliance costs already have been approved by the Commission in conjunction with the Company's ECR compliance plans and are eligible for recovery through the ECR. Thus the Company already has an established cost recovery mechanism in place to recover such costs on a timely basis once they are incurred and are known and measurable. If and when the Company actually incurs these projected NOx compliance costs, and if it is unable recover them through the ECR, then it may seek to recover them through base rates in a future base rate proceeding.

Finally, if the Commission allows depreciation rates to be increased for post test year projected capital additions for NOx compliance, then there no longer will exist any test year boundary requiring the exclusion of any post test year capital additions. Unfortunately, such a precedent could be relied upon by the Company or other Companies in the future to justify other selective post test year adjustments that will increase their revenue requirements.

Q. Have you quantified the effects on the depreciation rates and the resulting depreciation expense of removing the future plant additions projected for NOx compliance from FERC plant account 312?

A. Yes. I have quantified the effects of removing the future plant additions projected for NOx compliance from FERC plant account 312 as an additional adjustment to the depreciation rates by FERC production plant location and depreciation expense previously computed with the removal of the Company's adjustments to historic gross salvage and cost of removal rates. The quantification is summarized on my

Exhibit___(LK-7). In the final step, I utilized the rates that I previously computed in "present rates" column lieu of the Company's present rates in order to quantify the incremental effects of this recommendation compared to my preceding recommendation.

Return on Common Equity

Q. Have you quantified the effect on the Company's revenue requirement of KIUC witness Mr. Baudino's recommendation for the required return on common equity?

A. Yes. I utilized the Company's cost of capital obtained from Rives Exhibit 2 and simply replaced the Company's requested return on common equity with Mr. Baudino's recommendation of 8.7% for electric and 8.9% for gas. The Company's requested return on common equity of 11.25% translates to a grossed-up return recoverable from ratepayers of 18.99%. KIUC's recommended returns on common equity translate to grossed-up returns recoverable from ratepayers of 14.69% for electric and 15.02% for gas. The quantification of the revenue requirement effects for electric and gas are detailed on my Exhibit___(LK-8).

III. TERMINATION OF THE EARNINGS SHARING MECHANISM

<u>The ESM should be Terminated; It is Not a Supplemental Form of Regulation</u>

Q. Should the Commission discontinue the ESM?

A. Yes. Although the ESM represented a reasonable alternative to the traditional form of regulation during the trial period, it no longer is reasonable or an alternative. To the contrary, the ESM likely will harm ratepayers through two simultaneous forms of regulation, resulting in the combination of traditional base rate increases and annual ESM rate increases. There no longer is any need to utilize the ESM as a means to transition to potential deregulation. It is highly unlikely that Kentucky will deregulate in the foreseeable future. In addition, the ESM has not served to reduce costs or improve the quality of service. In any event, particularly in a period of increasing costs, traditional regulation provides a greater incentive to reduce costs than does ESM regulation because the Company retains the entire benefit of any such cost reductions between traditional base rate increases.

Q. How have circumstances changed since the Commission offered the Company the ESM as an alternative form of regulation in lieu of traditional regulation?

A. First, the Company filed for substantial base rate increases in December 2003 pursuant to traditional ratemaking, thus belying the notion that the ESM is an alternative form of regulation. The net import of the Company's decision to file for a traditional base rate increase is that any increase from such a filing will be effective mid-year 2004, which will follow in short order the anticipated 2003 ESM increases that will be effective in April 2004, and which will again be compounded by the anticipated 2004 ESM increases that will be effective in April 2005 and continue through March 2006.

Second, the Company now projects increasing costs, at least through 2006, according to financial projections developed by the Company and shared with BWG during the conduct of the management audit. Also, the Company plans to add additional generating capacity in the next two years, according to recent press releases announcing its intent to file for a traditional base rate increase in December 2003. These increases in costs have the potential to result in additional traditional base rate increases compounded by a continuing series of annual rate increases pursuant to the ESM.

Third, deregulation of generation in Kentucky and nationwide no longer appears inevitable or even likely. The ESM was conceived, according to statements by the Commission in its Case Nos. 98-474 Order, as an interim step toward the potential deregulation of generation and the related market pricing for such generation.

Fourth, the Company acknowledges that the ESM has not operated to reduce costs or improve the quality of service. The Company attributes any reductions in costs or improvements in the quality of service that have been achieved to its own independent initiatives undertaken for the benefit of their shareholder.

Q. Does the Company view the ESM as an *alternative* form of regulation or as a *supplemental* form of regulation?

A. The Company clearly views the ESM as a supplemental form of regulation that can exist simultaneously with the traditional cost of service form of regulation. As evidenced by its request for a substantial base rate increase in this proceeding, the Company does not consider the ESM to be a mutually exclusive form of regulation precluding the filing of traditional base rate cases. In Case No. 2003-00335, Company witness Mr. Beer states unequivocally that "LG&E and KU have a fundamental statutory right to seek a base rate increase regardless of whether they are operating under an ESM. . . The statutory grants of authority to the Commission from the General Assembly do not provide the Commission the power to alter or amend these rights." (Beer Direct, 4-5).

If the Company is legally correct in its position that the ESM and traditional ratemaking are not mutually exclusive, then the ESM necessarily will operate to supplement the traditional ratemaking process. The ESM provides for annual rate changes, which likely will be increases based on the Company's projection of increasing costs, on an interim basis until traditional base rate increases are implemented. Thus, the ESM will operate as a supplemental form of regulation, not an alternative form of regulation.

Q. Has the ESM operated as an effective incentive to increase the Company's managerial efficiency or to reduce its costs compared to traditional regulation?

A. No. Neither the Company nor the Commission's auditor, Barrington-Wellesley Group ("BWG") have identified a single initiative, cost reduction, or quality of service improvement that was the result of the ESM. To the contrary, the Company's initiatives to achieve efficiency and customer service have been independent of the existence of the ESM. In its Final Report Section V-5, BWG claimed that the ESM had increased managerial incentives. However, in Case No. 2003-00335, Company witness Mr. Beer disputed that conclusion, stating that "This particular finding has no application to companies like LG&E and KU. . . LG&E and KU will continue in the future, as they have in the past, to operate through innovation and achieve efficiencies with high quality customer service. Thus, while the ESM has not created a new corporate mindset for LG&E and KU, it has served to re-enforce corporate initiatives to achieve efficiency and customer service." (Beer Direct, 6-7).

Q. Does the Company project for the years 2003-2006 that it will earn less than the 10.5% lower threshold of the ESM earning deadband?

A. Yes. The BWG audit report stated that "Current projections indicate that the Companies will remain in an under-earning position for the next several years." (Final Report, I-10). For this conclusion, BWG relied upon the Companies' forecasts for the years 2003-2006 and confirmed these projections in interviews with Mr. Rives and Ms. Scott. The Company also confirmed its projections of underearnings in response to KIUC 1-10 in that proceeding.

Q. What is the significance of the Company's projections that it will underearn the lower threshold of the ESM earnings deadband at least through 2006 absent a traditional rate increase?

A. The Company may file traditional rate increase requests in addition to the request in this proceeding. In addition to these traditional base rate increases, the Company may obtain additional annual rate increases through the ESM, to the extent it is continued.

Q. Does the ESM provide greater incentives to the Company to reduce costs than traditional ratemaking?

A. No. To the extent ratemaking provides any incentives to the Company to reduce costs, then traditional ratemaking provides greater incentives than the ESM simply due to the ability of the Company to retain the entirety of the savings benefits and for longer periods of time. I generally agree with BWG that "COSR provides incentives for the regulated utility to control costs and optimize the utilization of rate base, some of the benefits of such efficiencies eventually flow to the utility's customers. . . COSR provides short-term immediate incentives to the utility to control costs between rate cases, but a large share of the benefits of efficiency improvements flow to the customers in the longer term." (BWG Report, I-9).

Q. How should the Commission discontinue the ESM?

A. The Commission should discontinue the ESM surcharge related to the ESM 2003 test year effective on the same date as any increase from this proceeding becomes effective.

Q. Why should the Commission discontinue the ESM surcharge related to the ESM 2003 test year effective on the same date as any increase from this proceeding becomes effective?

A. The ESM rate increase and the traditional base rate increase from this proceeding are mutually exclusive pursuant to alternative forms of regulation. Both represent prospective rate increases. The test years for the ESM and the traditional rate increase overlap for nine months, thus effectively providing double recovery of the revenue deficiencies associated with essentially the same revenue requirement. As such, the traditional rate increase from this proceeding will be piled on to the rate increase from the ESM if the ESM surcharge is not terminated on the same date as the traditional rate increase is effective. Doubling up on rate increases for essentially the same test period necessarily results in excessive rates that cannot be just and reasonable.

Q. The Commission allowed the Company to continue the ESM beyond the initial three year period subject to prospective change in Case No. 2002-00473 and retained BWG to conduct a management audit to determine whether the ESM should be continued. BWG issued its Final Report on August 31, 2003, recommending the continuation of the ESM. The Commission initiated "new investigations" of the ESM in its Order in Case No. 2003-00335 dated September 4, 2003. When did the Company decide to develop a traditional base rate filing?

A. The Company made this decision in June 2003 or before. The Company's consultants and counsel retained to support its efforts in this proceeding commenced billing on the project in June 2003, according to the Company's response to PSC 1-57.

Q. What is the significance of the fact that the Company already was preparing a base rate increase filing at the very time the Commission's auditor was conducting the management audit to determine whether the ESM should be continued.

A. This information was a material fact and directly relevant to the very issue being investigated by the Commission. This fact should have been disclosed to the Commission's auditors during the conduct of the management audit so that it could be reported to the Commission, Staff, and other parties with an interest in the Company's rates. Such information could have been considered by the Commission prior to its decision on September 4, 2003 to continue the ESM. It may have resulted in a completely different decision. Such information would have allowed KIUC and other parties to oppose the continuance of the ESM and seek an expedited hearing in order to terminate the ESM prior to the end of 2003.

The Commission should consider the failure of the Company to disclose this critical information to the Commission's auditors on the timing of the termination of the ESM surcharge. The Company's failure to disclose this critical and directly relevant information prior to the Commission's September 4, 2003 Order is an additional reason why the Commission should terminate the surcharge on the effective date of the rate change in this proceeding.

Q. The Company apparently considers the ESM to be a true-up mechanism for the historic period. Do you agree?

A. No. The Commission offered the Company the ESM as an alternative to traditional regulation. The structure of the ESM provides for annual rate changes prospectively on April 1 of the year following the calendar year test year based on that historic test year. The structure of the ESM follows that of traditional ratemaking with the use of a historic test year to set rates prospectively. The ESM simply established an annual and expedited ratemaking process for prospective rate changes, along with a sharing of revenue surpluses and deficiencies outside the earnings deadband.

The ESM did not disturb the fundamental ratemaking principle that base rates may be changed only prospectively. The Company's argument that the ESM operates as a true-up mechanism necessarily rests upon the assumption that the Commission can change a lawful rate retroactively. To the contrary, KRS §278.270 states that "Whenever the Commission, upon its own motion or upon complaint as provided in KRS 278.260, and after a hearing had upon reasonable notice, finds that any rate is unjust, unreasonable, insufficient, unjustly discriminatory or otherwise in violation of any of the provisions of this chapter, the commission shall by order prescribe a just and reasonable rate to be followed in the future."

Just and reasonable rates to be followed in the future may be set under either of the two different methodologies, but just and reasonable rates to be followed in the future cannot be established under two different methodologies based upon a largely overlapping test year and then implemented simultaneously as sought by the Company.

Q. How does the Company's request to implement simultaneous prospective rate increases under two alternative forms of regulation compare to the Commission's initial implementation of the ESM in conjunction with a base rate reduction under traditional ratemaking?

A. When the ESM initially was implemented, the Commission was careful to avoid the simultaneous operation of the two alternative forms of regulation and such doubling up. The base rate reduction based on traditional ratemaking was implemented prospectively on March 1, 2000 and used a 1998 test year. The first ESM rates were implemented prospectively on April 1, 2001 and used a 2000 test year. In contrast, the Company's request in this proceeding utilizes essentially the same test year to determine its revenue deficiencies under both the ESM and traditional forms of ratemaking with the simultaneous prospective implementation of the rate increases.

Q. Is there additional evidence that the Commission considered the ESM to set rates prospectively rather than operate as a true-up mechanism for a historic period?

A. Yes. The Commission offered the Company the ESM in its Order in Case No. 98-474, which the Company accepted in lieu of traditional regulation. The Commission also reduced the Company's base rates in accordance with traditional regulation effective March 1, 2000. Nevertheless, the Commission required the Company to annualize that rate reduction for the ESM test year 2000. Thus, when rates were reset prospectively on April 1, 2001, the rates did not double up the effects of the March 1, 2000 reduction. Consequently, rates were reduced less on April 1, 2001 pursuant to the new form of regulation than if the ESM had operated as a true-up mechanism.

The Company supported this treatment when the ESM was implemented and KIUC agreed with this treatment because the ESM reset base rates prospectively. The Commission should reject the Company's argument now to consider the ESM a true-up mechanism, an argument that is in direct contradiction to the position it took when the ESM was implemented.

Transitioning the ESM if It is Not Discontinued

Q. How should the Commission reflect the mid-year 2004 traditional base rate increases, if any, in the ESM 2004 test year if it is not discontinued?

A. The Commission should annualize the mid-year 2004 rate increases as if they were in effect the entire year.

Q. Why should the Commission annualize the mid-year 2004 traditional base rate increases, if any, in the ESM?

A. Such an approach is consistent procedurally and methodologically with the Commission's annualization of the March 1, 2000 rate reductions in the initial 2000 ESM test year. In Case No. 98-474, the Company specifically sought rehearing on this issue, proposing that the rate reductions be annualized to January 1, 2000 as if they had been in effect the entire year. No party contested the Companies' request. The Commission stated in its Orders on rehearing the following:

> **The impacts of the Orders issued in this proceeding should be reflected in the normalization of LG&E's [KU's] revenues for purposes of the initial ESM review. That initial review will cover LG&E's [KU's] operations for calendar year 2000. Since the Orders in this case were issued during this calendar year, the Commission finds it reasonable to reflect a full 12 months of the impact of these Orders in the initial ESM review.**

Similarly, the Commission should annualize any rate increases to January 1, 2004 as if they had been in effect the entire year. The precedent has been established, and at the Company's request. There is no valid reason to depart from this precedent simply because the change in base rates is an increase rather than a decrease.

The failure to annualize any rate increases to January 1, 2004 would be inequitable and penalize ratepayers in addition to the excessive and doubled up rates resulting from the ESM 2003 test year coupled with any traditional rate increase in this proceeding. The annualization of the rate reductions in the initial ESM test year decreased the earnings available for sharing with ratepayers. To be symmetrical, just, and reasonable, the Commission should ensure that the rate increases in the ESM 2004 test year increase the earnings available (or reduce the amounts recoverable) for sharing with ratepayers.

<u>The ESM should be Modified If It is Continued</u>

Q. If the ESM is continued, should the Commission consider it as an alternative form of regulation, as originally intended, or allow it to be utilized in addition to traditional regulation as a supplemental form of regulation between base rate cases?

A. The Commission should decide which form of regulation is appropriate for the Company. If the Commission decides to offer the Company another three years of ESM regulation, then it should include a condition whereby the Company would agree to refrain from filing another traditional base rate increase with an effective date during the term of the ESM regulation and surcharge period. If the Company is unwilling to accept that condition, then the ESM should be discontinued regardless of the other merits of termination.

The Commission should not change the nature of the ESM to provide a supplemental form of regulation in addition to traditional regulation. In Case Nos. 98-474, the Commission offered the Company the ESM as an alternative to traditional regulation, noting in its Orders that "[T]he Commission will now offer LG&E an alternative to traditional regulation in the form of an optional ESM plan." The Commission further noted that "[O]ur Order in Case No. 97-300 specified that LG&E could choose traditional or alternative rate-making."

Q. Should the Commission annualize any mid-year 2004 traditional base rate increases, if it continues the ESM?

A. Yes. Although I discussed this issue previously in conjunction with discontinuing the ESM, the same rationale for such annualization applies if the ESM is continued. The Commission already has established the precedent for such revenue annualizations and at the request of the Company. Thus, there is no valid rationale to argue against such annualizations, regardless of whether the ESM is continued or terminated.

Q. Should the Commission revise the return on equity utilized as the midpoint for the earnings deadband if it continues the ESM?

A. Yes. The Commission should revise the midpoint return on equity to the return authorized in this proceeding for the traditional base rate increase. The Commission should modify the terms of the ESM to reflect changed circumstances. The 11.5% ESM return on equity midpoint was established more than three years ago and does not reflect the current cost of common equity. The midpoint is used to set the upper and lower thresholds of the earnings deadband. The Commission's determination of the proper and current cost of common equity will directly impact the level of the ESM annual rate increases given that the Company projects it will earn below the lower threshold of the current deadband at least through 2006.

Q. Should the Commission require that the earned returns be computed using average monthly capitalization rather than year end capitalization?

A. Yes. The Commission should explicitly require the use of average capitalization if the ESM is continued. This was a contested issue in the Company's initial ESM filing and was resolved through a Global Settlement in Case Nos. 2001-054 and 2001-055, but only through 2002.

The use of average capitalization provides a far superior measure of the earnings achieved during the ESM test year than does year end capitalization. Average capitalization provides a better matching of all ratemaking components for the test year.

IV. BASE RATE REDUCTIONS UPON EXPIRATION OF MERGER SAVINGS AND VDT SURCREDITS

Q. Please describe the costs included in the Company's revenue requirement related to the LG&E and KU merger.

A. In total, the Company has included $38.494 million (electric) in the revenue requirement to reflect the merger savings. The Company has included $19.247 million in operating expense for the shareholder's portion of the merger savings. In addition, the Company has included the $19.247 million ratepayer share of the merger savings in the base revenue requirement. This latter amount is included by virtue of the Company using its total operating revenues as the starting point for operating income, but then not removing the effects of the merger surcredit in the same manner that it removes other surcharge revenues and costs such as those for the ESM, DSM, and ECR.

Q. Please describe the costs included in the Company's revenue requirement related to the 2001 employee buyout.

A. The Company has included $33.3000 million (electric) and $8.625 million (gas) in the revenue requirement to reflect the 2001 employee buyout. I described these costs previously in conjunction with the Company's failure to achieve labor cost savings.

Q. When are the merger surcredit and the VDT surcredit scheduled to terminate?

A. The merger surcredit is scheduled to terminate on June 30, 2008. The VDT surcredit is scheduled to terminate on March 31, 2006.

Q. Why should the Commission be concerned about the scheduled termination dates of the merger surcredit and VDT surcredit in this proceeding?

A. The Company's base revenue requirement includes $72 million (electric) and $9 million (gas) of such costs. It is essential that when each of these surcredits terminate, and therefore the ratepayer sharing of the underlying savings terminates, that base rates be adjusted downward to remove all related costs included in the revenue requirement. Otherwise, ratepayers will be penalized, continuing to pay as if the surcredits remained in effect and as if there were continuing VDT costs to amortize even though they will be fully amortized upon the termination of the VDT surcredit.

Q. **What is your recommendation?**

A. I recommend that the Company direct the Company in this proceeding to reduce its base rates by the amounts included in its allowed revenue requirement related to each of the surcredits upon their expiration, March 31, 2006 for the VDT surcredit and June 30, 2008 for the merger surcredit.

V. IMPLEMENTATION OF SYSTEM SALES CLAUSE

Q. Please explain why the Commission should implement a System Sales Clause for the Company.

A. First, a System Sales Clause is essential in order to capture on a consistent basis the interrelated effects of the Company's variable fuel costs, purchased power costs, and off-system sales revenues. Currently, the Company's Fuel Adjustment Clause ("FAC") includes all recoverable fuel and purchased power costs, but only removes the fuel costs associated with off-system sales, net of the amounts rolled into base rates. All off-system sales margins above or below the amounts embedded into base rates in the last base rate proceeding are retained by the Company. Unlike recoverable fuel and purchased power costs, there currently is no rate mechanism to capture in whole or part the variability in the off-system sales margins compared to the amounts embedded into base rates.

Second, the Company has included $64 million in test year capitalization for the new Trimble County CTs (7-10) that are scheduled to enter commercial service in April 2004 and June 2004. This amount represents nearly 80% of the estimated completion cost. This additional capacity will provide the Company the opportunity to make additional off-system sales compared to the test year. As a matter of equity, if the ratepayers are required to pay for this capacity, then they should benefit at least in part from the additional off-system sales margins that will be achieved due to this capacity.

Q. How should the Commission implement such a System Sales Clause?

A. I recommend that the Commission pattern a System Sales Clause after the Kentucky Power Company ("KPC") Sales Clause. The KPC System Sales Clause provides for a 50% to Company and 50% to ratepayers sharing of the net change in off-system sales margins compared to the amount embedded into base rates. I have attached a copy of the KPC System Sales Clause tariff for reference purposes as my Exhibit___(LK-9).

Q. Does this complete your testimony?

A. Yes.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Expert Testimony Appearances of Lane Kollen As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms.	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

Expert Testimony Appearances
of
Lane Kollen
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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) (Surrebuttal)	LA	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

Expert Testimony Appearances of Lane Kollen As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear llife extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02 (Supplemental Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission Statt	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of March 2004**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

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Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year *Adjustments.*
04/04	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527 I	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KU	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 *(Consolidated*	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
04/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2004**

Date	Case	Jurisdict.	Party	Utility	Subject
04/03	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.

EXHIBIT ____(LK-2)

Louisville Gas and Electric Company
Case No. 2003-00433
Analysis of Salaries and Wages
For the Calendar Years 1998 through 2002 and the Test Year
"000 Omitted"

		Calendar Years Prior to Test Year										Test Year	
		5th		4th		3rd		2nd		1st			
Line No.	Item (a)	Amount (b)	% (c)	Amount (d)	% (e)	Amount (f)	% (g)	Amount (h)	% (I)	Amount (j)	% (k)	Amount (l)	% (m)
1	Wages charged to expense												
2	Power Production Expense	37,126	-2.00%	37,025	-0.27%	36,291	-1.98%	27,415	-24.46%	27,894	1.75%	28,473	2.08%
3	Transmission Expense	2,475	-6.64%	2,021	-18.34%	1,797	-11.08%	1,404	-21.87%	1,215	-13.46%	1,441	18.60%
4	Distribution Expense	15,496	12.36%	13,593	-12.28%	13,390	-1.49%	10,171	-24.04%	8,453	-16.89%	9,468	12.01%
5	Customer Accounts Expense	8,311	-6.18%	7,795	-6.21%	7,708	-1.12%	2,644	-65.70%	2,642	-0.08%	5,676	114.84%
6	Sales Expense	1,495	-2.22%	1,747	16.86%	1,278	-26.85%	0	-100.00%	0		51	
7	Expenses - Gas Business	12,599	-3.17%	11,614	-7.82%	10,708	-7.80%	8,987	-16.07%	8,357	-7.01%	9,072	8.56%
8	Administrative and General Expenses:												
	(a) Administrative and General Salaries	15,667	-1.73%	15,225	-2.82%	15,068	-1.03%	22,983	52.53%	23,123	0.61%	20,483	-11.42%
	(b) Office Supplies and Expenses												
	(c) administrative Exp. Transferred - credit												
	(d) Outside services employed												
	(e) Property insurance												
	(f) Injuries and damages												
	(g) Employee pensions and benefits												
	(h) Franchise requirements												
	(I) Regulatory comminssion expense												
	(j) Duplicate charges - credit												
	(k) Miscellaneous general expense												
	(l) Maintenance of general plant												
9	Total Administrative and General Expenses L8(a) through L8(l)	15,667	-1.73%	15,225	-2.82%	15,068	-1.03%	22,983	0.61%	23,123	0.61%	20,483	-11.42%

Attachment to PSC Question No. 23(c)
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Louisville Gas and Electric Company
Case No. 2003-00433
Analysis of Salaries and Wages
For the Calendar Years 1998 through 2002 and the Test Year
"000 Omitted"

Line No.	Item (a)	Calendar Years Prior to Test Year: 5th Amount (b)	5th % (c)	4th Amount (d)	4th % (e)	3rd Amount (f)	3rd % (g)	2nd Amount (h)	2nd % (i)	1st Amount (j)	1st % (k)	Test Year Amount (l)	Test Year % (m)
10	Total Salaries and Wages charged expense (L2 through L7 + L8)	93,169	-11.29%	89,020	-33.71%	86,240	-52.38%	73,604	-199.00%	71,684	-34.47%	74,664	133.24%
11	Wages Capitalized	20,509		18,026	-12.11%	18,719	3.84%	11,650	-9.00%	10,601	-9.00%	10,170	-4.07%
12	Total Salaries and Wages (1)	113,678	-11.29%	107,046	-5.83%	104,959	-1.95%	85,254	-18.77%	82,285	-3.48%	84,834	3.10%
13	Ratio of salaries and wages charged to expense to total wages (L10/L12)	0.82		0.83		0.82		0.86		0.87		0.88	
14	Ratio of salaries and wages capitalized to total wages (L11/L12)	0.18		0.17		0.18		0.14		0.13		0.12	

Note: Show percent increae of each year over the prior year in Columns (c), (e), (g), (i), (k), and (m).

Note: Salaries and wages above contain overhead amounts and represent total amount charged to LG&E. For example, Servco employees would charge LG&E for services performed for LG&E.

Total overtime dollars (electric and gas) expended below represent all overtime charged to LG&E regardless of what company the employee works for.

	Amount	% Incr
Test Year	7,203,831	23.70%
1st Calendar Year Prior to Test Year	5,823,756	-42.07%
2nd Calendar Year Prior to Test Year	10,053,044	-14.29%
3rd Calendar Year Prior to Test Year	11,729,640	1.11%
4th Calendar Year Prior to Test Year	11,600,336	-5.92%
5th Calendar Year Prior to Test Year	12,330,678	

(1) Does not include salaries and wages in balance sheet accounts other than Utility Plant and Removal

Attachment to PSC Question No. 23(c)
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Louisville Gas and Electric
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

				Estimated Future Net Salvage						Interim Retirement Rate Calculation							
Account No.	Location Code	Description	Original Cost 12/31/02	Interim Net Salvage %	Interim Net Salvage Amount	Terminal Net Salvage %	Terminal Net Salvage Amount	Total Net Salvage %	Total Net Salvage Amount	Interim Ret ASL/Curve	Avg Age At Ret. (Yrs)	Iowa Curve Percent Surv	Percent Retirement	Interim Retired Amount	Interim Retired Rate	Factored Amount	Interim Ret. % Of Total Investment
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
		DEPRECIABLE PLANT															
		STEAM PLANT															
311.00		**Structures and Improvements**															
	112	Cane Run Unit 1	4,182,197.33	-0.9%	-37,640	0.0%	0	-0.9%	-37,640	120-S1	43.2	94%	6%	250,932	-15%	-37,640	-0.9%
	121	Cane Run Unit 2	2,102,941.66	-0.9%	-18,926	0.0%	0	-0.9%	-18,926	120-S1	43.2	94%	6%	126,176	-15%	-18,926	-0.9%
	131	Cane Run Unit 3	3,532,140.77	-0.9%	-31,789	0.0%	0	-0.9%	-31,789	120-S1	43.2	94%	6%	211,928	-15%	-31,789	-0.9%
	141	Cane Run Unit 4	3,547,227.06	-0.9%	-31,925	-25.2%	-893,901	-26.1%	-925,826	120-S1	43.2	94%	6%	212,834	-15%	-31,925	-0.9%
	142	Cane Run Unit 4 Scrubber	760,360.00	-0.9%	-6,843	-25.2%	-191,611	-26.1%	-198,454	120-S1	43.2	94%	6%	45,622	-15%	-6,843	-0.9%
	151	Cane Run Unit 5	5,416,846.93	-0.9%	-48,752	-21.0%	-1,137,538	-21.9%	-1,186,289	120-S1	43.2	94%	6%	325,011	-15%	-48,752	-0.9%
	152	Cane Run Unit 5 Scrubber	1,696,435.28	-0.9%	-15,268	-21.0%	-356,251	-21.9%	-371,519	120-S1	43.2	94%	6%	101,786	-15%	-15,268	-0.9%
	161	Cane Run Unit 6	18,149,961.41	-0.9%	-163,350	-8.2%	-1,488,297	-9.1%	-1,651,646	120-S1	43.2	94%	6%	1,088,998	-15%	-163,350	-0.9%
	162	Cane Run Unit 6 Scrubber	1,859,591.50	-0.9%	-16,736	-8.2%	-152,487	-9.1%	-169,223	120-S1	43.2	94%	6%	111,575	-15%	-16,736	-0.9%
	211	Mill Creek Unit 1	18,350,957.82	-0.9%	-165,159	-10.6%	-1,945,202	-11.5%	-2,110,360	120-S1	43.2	94%	6%	1,101,057	-15%	-165,159	-0.9%
	212	Mill Creek Unit 1 Scrubber	1,697,743.03	-0.9%	-15,280	-10.6%	-179,961	-11.5%	-195,240	120-S1	43.2	94%	6%	101,865	-15%	-15,280	-0.9%
	221	Mill Creek Unit 2	10,703,506.13	-0.9%	-96,332	-18.1%	-1,937,335	-19.0%	-2,033,666	120-S1	43.2	94%	6%	642,210	-15%	-96,332	-0.9%
	222	Mill Creek Unit 2 Scrubber	1,393,403.67	-0.9%	-12,541	-18.1%	-252,206	-19.0%	-264,747	120-S1	43.2	94%	6%	83,604	-15%	-12,541	-0.9%
	231	Mill Creek Unit 3	24,487,440.44	-0.9%	-220,387	-11.1%	-2,718,106	-12.0%	-2,938,493	120-S1	43.2	94%	6%	1,469,246	-15%	-220,387	-0.9%
	232	Mill Creek Unit 3 Scrubber	362,866.58	-0.9%	-3,266	-11.1%	-40,278	-12.0%	-43,544	120-S1	43.2	94%	6%	21,772	-15%	-3,266	-0.9%
	241	Mill Creek Unit 4	56,594,172.78	-0.9%	-509,348	-5.6%	-3,169,274	-6.5%	-3,678,621	120-S1	43.2	94%	6%	3,395,650	-15%	-509,348	-0.9%
	242	Mill Creek Unit 4 Scrubber	5,079,085.65	-0.9%	-45,712	-5.6%	-284,429	-6.5%	-330,141	120-S1	43.2	94%	6%	304,745	-15%	-45,712	-0.9%
	311	Trimble County Unit 1	161,248,919.71	-0.9%	-1,451,240	-2.1%	-3,386,227	-3.0%	-4,837,468	120-S1	43.2	94%	6%	9,674,935	-15%	-1,451,240	-0.9%
	312	Trimble County Unit 1 Scrubbe	450,053.78	-0.9%	-4,050	-2.1%	-9,451	-3.0%	-13,502	120-S1	43.2	94%	6%	27,003	-15%	-4,050	-0.9%
		Total Account 311	321,615,851.53	-0.9%	-2,894,543	-5.6%	-18,142,553	-6.5%	-21,037,095								
312.00		**Boiler Plant Equipment**															
	103	Cane Run Locomotive	51,549.42	-7.6%	-3,918	0.0%	0	-7.6%	-3,918	50-L0.5	30.3	62%	38%	19,589	-20%	-3,918	-7.6%
	104	Cane Run Rail Cars	1,501,772.81	-7.6%	-114,135	0.0%	0	-7.6%	-114,135	50-L0.5	30.3	62%	38%	570,674	-20%	-114,135	-7.6%
	112	Cane Run Unit 1	1,053,742.53	-7.6%	-80,084	0.0%	0	-7.6%	-80,084	50-L0.5	30.3	62%	38%	400,422	-20%	-80,084	-7.6%
	121	Cane Run Unit 2	132,836.82	-7.6%	-10,096	0.0%	0	-7.6%	-10,096	50-L0.5	30.3	62%	38%	50,478	-20%	-10,096	-7.6%
	131	Cane Run Unit 3	716,616.30	-7.6%	-54,463	0.0%	0	-7.6%	-54,463	50-L0.5	30.3	62%	38%	272,314	-20%	-54,463	-7.6%
	141	Cane Run Unit 4	25,980,016.48	-7.6%	-1,974,481	-5.9%	-1,532,821	-13.5%	-3,507,302	50-L0.5	30.3	62%	38%	9,872,406	-20%	-1,974,481	-7.6%
	142	Cane Run Unit 4 Scrubber	16,701,761.03	-7.6%	-1,269,334	-5.9%	-985,404	-13.5%	-2,254,738	50-L0.5	30.3	62%	38%	6,346,669	-20%	-1,269,334	-7.6%
	151	Cane Run Unit 5	21,717,140.89	-7.6%	-1,650,503	-9.1%	-1,976,260	-16.7%	-3,626,763	50-L0.5	30.3	62%	38%	8,252,514	-20%	-1,650,503	-7.6%
	152	Cane Run Unit 5 Scrubber	27,928,602.90	-7.6%	-2,122,574	-9.1%	-2,541,503	-16.7%	-4,664,077	50-L0.5	30.3	62%	38%	10,612,869	-20%	-2,122,574	-7.6%
	161	Cane Run Unit 6	35,613,831.67	-7.6%	-2,706,651	-7.2%	-2,564,196	-14.8%	-5,270,847	50-L0.5	30.3	62%	38%	13,533,256	-20%	-2,706,651	-7.6%
	162	Cane Run Unit 6 Scrubber	30,524,761.84	-7.6%	-2,319,882	-7.2%	-2,197,783	-14.8%	-4,517,665	50-L0.5	30.3	62%	38%	11,599,409	-20%	-2,319,882	-7.6%
	203	Mill Creek Locomotive	613,424.43	-7.6%	-46,620	0.0%	0	-7.6%	-46,620	50-L0.5	30.3	62%	38%	233,101	-20%	-46,620	-7.6%
	204	Mill Creek Rail Cars	3,631,645.61	-7.6%	-276,005	0.0%	0	-7.6%	-276,005	50-L0.5	30.3	62%	38%	1,380,025	-20%	-276,005	-7.6%
	211	Mill Creek Unit 1	40,535,760.73	-7.6%	-3,080,718	-8.3%	-3,364,468	-15.9%	-6,445,186	50-L0.5	30.3	62%	38%	15,403,589	-20%	-3,080,718	-7.6%
	212	Mill Creek Unit 1 Scrubber	33,874,404.57	-7.6%	-2,574,455	-8.3%	-2,811,576	-15.9%	-5,386,030	50-L0.5	30.3	62%	38%	12,872,274	-20%	-2,574,455	-7.6%
	221	Mill Creek Unit 2	33,397,635.49	-7.6%	-2,538,220	-10.0%	-3,339,764	-17.6%	-5,877,984	50-L0.5	30.3	62%	38%	12,691,101	-20%	-2,538,220	-7.6%
	222	Mill Creek Unit 2 Scrubber	34,412,558.24	-7.6%	-2,615,354	-10.0%	-3,441,256	-17.6%	-6,056,610	50-L0.5	30.3	62%	38%	13,076,772	-20%	-2,615,354	-7.6%
	231	Mill Creek Unit 3	65,259,053.22	-7.6%	-4,959,688	-6.1%	-3,980,802	-13.7%	-8,940,490	50-L0.5	30.3	62%	38%	24,798,440	-20%	-4,959,688	-7.6%
	232	Mill Creek Unit 3 Scrubber	52,369,621.74	-7.6%	-3,980,091	-6.1%	-3,194,547	-13.7%	-7,174,638	50-L0.5	30.3	62%	38%	19,900,456	-20%	-3,980,091	-7.6%
	241	Mill Creek Unit 4	154,787,100.00	-7.6%	-11,763,820	-3.0%	-4,643,613	-10.6%	-16,407,433	50-L0.5	30.3	62%	38%	58,819,098	-20%	-11,763,820	-7.6%
	242	Mill Creek Unit 4 Scrubber	105,450,790.06	-7.6%	-8,014,260	-3.0%	-3,163,524	-10.6%	-11,177,784	50-L0.5	30.3	62%	38%	40,071,300	-20%	-8,014,260	-7.6%
	311	Trimble County Unit 1	235,442,385.84	-7.6%	-17,893,621	-2.1%	-4,944,290	-9.7%	-22,837,911	50-L0.5	30.3	62%	38%	89,468,107	-20%	-17,893,621	-7.6%
	312	Trimble County Unit 1 Scrubbe	54,528,851.05	-6.4%	-3,489,846	-2.1%	-1,145,106	-8.5%	-4,634,952	50-L0.5	30.3	68%	32%	17,449,232	-20%	-3,489,846	-6.4%
		Total Account 312	976,225,863.67	-7.5%	-73,538,819	-4.7%	-45,826,911	-12.2%	-119,365,731								

Louisville Gas and Electric

Electric Division

Summary of Original Cost of Utility Plant In Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
314.00		**Turbogenerator Units**															
	112	Cane Run Unit 1	106,008.55	-4.2%	-4,452	0.0%	0	-4.2%	-4,452	50-S1.5	38.6	58%	42%	44,524	-10%	-4,452	-4.2%
	121	Cane Run Unit 2	19,998.97	-4.2%	-840	0.0%	0	-4.2%	-840	50-S1.5	38.6	58%	42%	8,400	-10%	-840	-4.2%
	131	Cane Run Unit 3	581,177.52	-4.2%	-24,409	0.0%	0	-4.2%	-24,409	50-S1.5	38.6	58%	42%	244,095	-10%	-24,409	-4.2%
	141	Cane Run Unit 4	8,608,132.78	-4.2%	-361,542	-5.7%	-490,664	-9.9%	-852,205	50-S1.5	38.6	58%	42%	3,615,416	-10%	-361,542	-4.2%
	151	Cane Run Unit 5	6,985,593.95	-4.2%	-293,395	-8.9%	-621,718	-13.1%	-915,113	50-S1.5	38.6	58%	42%	2,933,949	-10%	-293,395	-4.2%
	161	Cane Run Unit 6	11,274,211.57	-4.2%	-473,517	-7.2%	-811,743	-11.4%	-1,285,260	50-S1.5	38.6	58%	42%	4,735,169	-10%	-473,517	-4.2%
	211	Mill Creek Unit 1	13,449,713.81	-4.2%	-564,888	-7.9%	-1,062,527	-12.1%	-1,627,415	50-S1.5	38.6	58%	42%	5,648,880	-10%	-564,888	-4.2%
	221	Mill Creek Unit 2	14,801,053.25	-4.2%	-621,644	-7.1%	-1,050,875	-11.3%	-1,672,519	50-S1.5	38.6	58%	42%	6,216,442	-10%	-621,644	-4.2%
	231	Mill Creek Unit 3	26,232,206.52	-4.2%	-1,101,753	-5.2%	-1,364,075	-9.4%	-2,465,827	50-S1.5	38.6	58%	42%	11,017,527	-10%	-1,101,753	-4.2%
	241	Mill Creek Unit 4	40,930,150.49	-4.2%	-1,719,066	-2.6%	-1,064,184	-6.8%	-2,783,250	50-S1.5	38.6	58%	42%	17,190,663	-10%	-1,719,066	-4.2%
	311	Trimble County Unit 1	66,236,375.14	-4.2%	-2,781,928	-1.7%	-1,126,018	-5.9%	-3,907,946	50-S1.5	38.6	58%	42%	27,819,278	-10%	-2,781,928	-4.2%
		Total Account 314	189,224,622.55	-4.2%	-7,947,434	-4.0%	-7,591,804	-8.2%	-15,539,238								
315.00		**Accessory Electric Equipment**															
	112	Cane Run Unit 1	1,891,012.53	-5.4%	-102,115	0.0%	0	-5.4%	-102,115	55-S1	55.0	73%	27%	510,573	-20%	-102,115	-5.4%
	121	Cane Run Unit 2	1,277,223.20	-5.4%	-68,970	0.0%	0	-5.4%	-68,970	55-S1	55.0	73%	27%	344,850	-20%	-68,970	-5.4%
	131	Cane Run Unit 3	767,324.52	-5.4%	-41,436	0.0%	0	-5.4%	-41,436	55-S1	55.0	73%	27%	207,178	-20%	-41,436	-5.4%
	141	Cane Run Unit 4	5,490,677.18	-5.4%	-296,497	-2.6%	-142,758	-8.0%	-439,254	55-S1	55.0	73%	27%	1,482,483	-20%	-296,497	-5.4%
	142	Cane Run Unit 4 Scrubber	987,949.29	-5.4%	-53,349	-2.6%	-25,687	-8.0%	-79,036	55-S1	55.0	73%	27%	266,746	-20%	-53,349	-5.4%
	151	Cane Run Unit 5	6,846,848.21	-5.4%	-369,730	-2.6%	-178,018	-8.0%	-547,748	55-S1	55.0	73%	27%	1,848,649	-20%	-369,730	-5.4%
	152	Cane Run Unit 5 Scrubber	2,173,037.73	-5.4%	-117,344	-2.6%	-56,499	-8.0%	-173,843	55-S1	55.0	73%	27%	586,720	-20%	-117,344	-5.4%
	161	Cane Run Unit 6	8,173,345.07	-5.4%	-441,361	-2.9%	-237,027	-8.3%	-678,388	55-S1	55.0	73%	27%	2,206,803	-20%	-441,361	-5.4%
	162	Cane Run Unit 6 Scrubber	2,124,667.29	-5.4%	-114,732	-2.9%	-61,615	-8.3%	-176,347	55-S1	55.0	73%	27%	573,660	-20%	-114,732	-5.4%
	211	Mill Creek Unit 1	14,520,069.59	-5.4%	-784,084	-2.1%	-304,921	-7.5%	-1,089,005	55-S1	55.0	73%	27%	3,920,419	-20%	-784,084	-5.4%
	212	Mill Creek Unit 1 Scrubber	5,541,694.53	-5.4%	-299,252	-2.1%	-116,376	-7.5%	-415,627	55-S1	55.0	73%	27%	1,496,258	-20%	-299,252	-5.4%
	221	Mill Creek Unit 2	7,420,343.06	-5.4%	-400,699	-4.1%	-304,234	-9.5%	-704,933	55-S1	55.0	73%	27%	2,003,493	-20%	-400,699	-5.4%
	222	Mill Creek Unit 2 Scrubber	4,451,153.72	-5.4%	-240,362	-4.1%	-182,497	-9.5%	-422,860	55-S1	55.0	73%	27%	1,201,812	-20%	-240,362	-5.4%
	231	Mill Creek Unit 3	13,482,711.35	-5.4%	-728,066	-2.9%	-390,999	-8.3%	-1,119,065	55-S1	55.0	73%	27%	3,640,332	-20%	-728,066	-5.4%
	232	Mill Creek Unit 3 Scrubber	2,531,772.82	-5.4%	-136,716	-2.9%	-73,421	-8.3%	-210,137	55-S1	55.0	73%	27%	683,579	-20%	-136,716	-5.4%
	241	Mill Creek Unit 4	21,428,489.73	-5.4%	-1,157,138	-5.5%	-1,178,567	-10.9%	-2,335,705	55-S1	55.0	73%	27%	5,785,692	-20%	-1,157,138	-5.4%
	242	Mill Creek Unit 4 Scrubber	5,811,079.36	-5.4%	-313,798	-5.5%	-319,609	-10.9%	-633,408	55-S1	55.0	73%	27%	1,568,991	-20%	-313,798	-5.4%
	311	Trimble County Unit 1	56,332,123.79	-5.4%	-3,041,935	-2.2%	-1,239,307	-7.6%	-4,281,241	55-S1	55.0	73%	27%	15,209,673	-20%	-3,041,935	-5.4%
	312	Trimble County Unit 1 Scrubbe	2,736,920.21	-5.4%	-147,794	-2.2%	-60,212	-7.6%	-208,006	55-S1	55.0	73%	27%	738,968	-20%	-147,794	-5.4%
		Total Account 315	163,988,443.18	-5.4%	-8,855,376	-3.0%	-4,871,747	-8.4%	-13,727,123								
316.00		**Miscellaneous Power Plant Equipment**															
	112	Cane Run Unit 1	151,638.76	-11.8%	-17,893	0.0%	0	-11.8%	-17,893	35-S2	29.9	41%	59%	89,467	-20%	-17,893	-11.8%
	131	Cane Run Unit 3	11,664.48	-11.8%	-1,376	0.0%	0	-11.8%	-1,376	35-S2	29.9	41%	59%	6,882	-20%	-1,376	-11.8%
	141	Cane Run Unit 4	54,253.32	-11.8%	-6,402	-10.9%	-5,914	-22.7%	-12,316	35-S2	29.9	41%	59%	32,009	-20%	-6,402	-11.8%
	142	Cane Run Unit 4 Scrubber	6,464.30	-11.8%	-763	-10.9%	-705	-22.7%	-1,467	35-S2	29.9	41%	59%	3,814	-20%	-763	-11.8%
	151	Cane Run Unit 5	42,867.49	-11.8%	-5,058	-17.6%	-7,545	-29.4%	-12,603	35-S2	29.9	41%	59%	25,292	-20%	-5,058	-11.8%

Louisville Gas and Electric
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
	152	Cane Run Unit 5 Scrubber	47,299.47	-11.8%	-5,581	-17.6%	-8,325	-29.4%	-13,906	35-S2	29.9	41%	59%	27,907	-20%	-5,581	-11.8%
	161	Cane Run Unit 6	1,806,951.04	-11.8%	-213,220	-0.5%	-9,035	-12.3%	-222,255	35-S2	29.9	41%	59%	1,066,101	-20%	-213,220	-11.8%
	162	Cane Run Unit 6 Scrubber	31,568.91	-11.8%	-3,725	-0.5%	-158	-12.3%	-3,883	35-S2	29.9	41%	59%	18,626	-20%	-3,725	-11.8%
	211	Mill Creek Unit 1	654,992.48	-11.8%	-77,289	-2.0%	-13,100	-13.8%	-90,389	35-S2	29.9	41%	59%	386,446	-20%	-77,289	-11.8%
	221	Mill Creek Unit 2	105,299.47	-11.8%	-12,425	-12.2%	-12,847	-24.0%	-25,272	35-S2	29.9	41%	59%	62,127	-20%	-12,425	-11.8%
	231	Mill Creek Unit 3	318,625.29	-11.8%	-37,598	-5.2%	-16,569	-17.0%	-54,166	35-S2	29.9	41%	59%	187,989	-20%	-37,598	-11.8%
	241	Mill Creek Unit 4	3,926,266.27	-11.8%	-463,299	-2.0%	-78,525	-13.8%	-541,825	35-S2	29.9	41%	59%	2,316,497	-20%	-463,299	-11.8%
	242	Mill Creek Unit 4 Scrubber	41,441.04	-11.8%	-4,890	-2.0%	-829	-13.8%	-5,719	35-S2	29.9	41%	59%	24,450	-20%	-4,890	-11.8%
	311	Trimble County Unit 1	2,332,701.72	-11.8%	-275,259	-3.3%	-76,979	-15.1%	-352,238	35-S2	29.9	41%	59%	1,376,294	-20%	-275,259	-11.8%
		Total Account 316	9,532,034.04	-11.8%	-1,124,780	-2.4%	-230,528	-14.2%	-1,355,308								
		Total Steam Production Plant	1,660,586,814.97	-5.7%	-94,360,952	-4.6%	-76,663,543	-10.3%	-171,024,496								
		HYDRAULIC PLANT Project 289															
331.10		**Structures and Improvements**															
	451	Ohio Falls Plant - Project 289	4,995,148.82	-8.1%	-404,607	-3.1%	-154,850	-11.2%	-559,457	140-L1.5	76.8	73%	27%	1,348,690	-30%	-404,607	-8.1%
332.10		**Reservoirs, Dams and Waterways**															
	451	Ohio Falls Plant - Project 289	303,530.35	-1.4%	-4,249	-51.3%	-155,711	-52.7%	-159,960	150-L1.5	48.0	91%	9%	27,318	-15%	-4,098	-1.4%
333.10		**Waterwheel, Turbines and Generators**															
	451	Ohio Falls Plant - Project 289	2,316,031.31	-0.5%	-11,580	-13.8%	-319,612	-14.3%	-331,192	150.L1.5	48.6	75%	25%	579,008	-2%	-11,580	-0.5%
334.10		**Accessory Electric Equipment**															
	451	Ohio Falls Plant - Project 289	1,304,908.02	-16.5%	-215,310	-5.7%	-74,380	-22.2%	-289,690	55-S1	41.6	34%	66%	861,239	-25%	-215,310	-16.5%
335.10		**Miscellaneous Power Plant Equipment**															
	451	Ohio Falls Plant - Project 289	151,460.96	-24.5%	-37,108	-6.7%	-10,148	-31.2%	-47,256	35-S2	46.5	2%	98%	148,432	-25%	-37,108	-24.5%
336.10		**Roads, Railroads and Bridges**															
	451	Ohio Falls Plant - Project 289	178,846.99	0.0%	0	0.0%	0	0.0%	0	150-L1			100%	178,847	0	0	0.0%
		Sub-Total Hydr. Plant - (Projec	9,249,926.45	-7.3%	-672,854	-7.7%	-714,701	-15.0%	-1,387,555								
		Other Than Project 289															
331.00		**Structures and Improvements**															
	450	Ohio Falls Plant - Non Project :	65,796.14	-5.1%	-3,356	0.0%	0	-5.1%	-3,356	140-L1.5	76.8	83%	17%	11,185	-30%	-3,356	-5.1%
335.00		**Miscellaneous Power Plant Equipment**															
	450	Ohio Falls Plant - Non Project :	7,813.67	-21.8%	-1,703	0.0%	0	-21.8%	-1,703	55-R3	46.5	13%	87%	6,798	-25%	-1,699	-21.8%
336.00		**Roads, Railroads and Bridges**															
	450	Ohio Falls Plant - Non Project :	1,133.98	0.0%	0	0.0%	0	0.0%	0	150-L1			100%	1,134	0%	0	0.0%
		Sub-Total Hydraulic Plant - (Other Than Project 289)	74,743.79	-6.8%	-5,059	0.0%	0	-6.8%	-5,059								

Table 2-a

Louisville Gas and Electric
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No.	Location Code	Description	Original Cost 12/31/02	Estimated Future Net Salvage: Interim Net Salvage %	Interim Net Salvage Amount	Terminal Net Salvage %	Terminal Net Salvage Amount	Total Net Salvage %	Total Net Salvage Amount	Interim Retirement Rate Calculation: Interim Ret ASL/Curve	Avg Age At Ret. (Yrs)	Iowa Curve Percent Surv	Percent Retirement	Interim Retired Amount	Interim Retired Rate	Factored Amount	Interim Ret. % Of Total Investment
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
		Total Hydraulic Plant	9,324,670.24	-7.3%	-677,913	-7.7%	-714,701	-14.9%	-1,392,614								
		OTHER PRODUCTION PLANT															
341.00		**Structures and Improvements**															
	171	Cane Run CT's	68,931.71	-1.7%	-1,172	-22.6%	-15,579	-24.3%	-16,750	80-L1	29.0	89%	11%	7,582	-15%	-1,137	-1.7%
	410	Zorn CT's	8,241.14	-1.7%	-140	-212.4%	-17,504	-214.1%	-17,644	80-L1	29.0	89%	11%	907	-15%	-136	-1.7%
	420	Waterside CT's	411,977.94	-1.7%	-7,004	-10.6%	-43,670	-12.3%	-50,673	80-L1	29.0	89%	11%	45,318	-15%	-6,798	-1.7%
	431	Paddys 12 CT	42,864.53	-1.7%	-729	-74.9%	-32,106	-76.6%	-32,834	80-L1	29.0	89%	11%	4,715	-15%	-707	-1.7%
	432	Paddys 13 CT	2,158,698.12	-1.7%	-36,698	-4.3%	-92,824	-6.0%	-129,522	80-L1	29.0	89%	11%	237,457	-15%	-35,619	-1.7%
	459	Brown 5 CT	858,538.64	-1.7%	-14,595	-7.4%	-63,532	-9.1%	-78,127	80-L1	29.0	89%	11%	94,439	-15%	-14,166	-1.7%
	460	Brown 6 CT	69,733.40	-1.7%	-1,185	-81.3%	-56,693	-83.0%	-57,879	80-L1	29.0	89%	11%	7,671	-15%	-1,151	-1.7%
	461	Brown 7 CT	105,588.33	-1.7%	-1,795	-27.8%	-29,354	-29.5%	-31,149	80-L1	29.0	89%	11%	11,615	-15%	-1,742	-1.7%
	470	Trimble County CT5	1,458,614.33	-1.7%	-24,796	-3.0%	-43,758	-4.7%	-68,555	80-L1	29.0	89%	11%	160,448	-15%	-24,067	-1.7%
	471	Trimble County CT6	1,457,842.69	-1.7%	-24,783	-3.0%	-43,735	-4.7%	-68,519	80-L1	29.0	89%	11%	160,363	-15%	-24,054	-1.7%
		Total Account 341	6,641,030.83	-1.7%	-112,898	-6.6%	-438,754	-8.3%	-551,652								
342.00		**Fuel Holders, Producers and Accessory**															
	171	Cane Run CT's	123,338.90	0.0%	0	-13.4%	-16,527	-13.4%	-16,527	80-L1	29.0	89%	11%	13,567	0%	0	0.0%
	410	Zorn CT's	12,801.77	0.0%	0	-145.6%	-18,639	-145.6%	-18,639	80-L1	29.0	89%	11%	1,408	0%	0	0.0%
	420	Waterside CT's	124,163.26	0.0%	0	-37.5%	-46,561	-37.5%	-46,561	80-L1	29.0	89%	11%	13,658	0%	0	0.0%
	430	Paddys 11 CT	9,237.57	0.0%	0	-179.4%	-16,572	-179.4%	-16,572	80-L1	29.0	89%	11%	1,016	0%	0	0.0%
	431	Paddys 12 CT	12,197.11	0.0%	0	-280.3%	-34,188	-280.3%	-34,188	80-L1	29.0	89%	11%	1,342	0%	0	0.0%
	432	Paddys 13 CT	2,233,773.85	0.0%	0	-4.4%	-98,286	-4.4%	-98,286	80-L1	29.0	89%	11%	245,715	0%	0	0.0%
	459	Brown 5 CT	822,580.92	0.0%	0	-8.2%	-67,452	-8.2%	-67,452	80-L1	29.0	89%	11%	90,484	0%	0	0.0%
	460	Brown 6 CT	363,762.04	0.0%	0	-34.5%	-125,498	-34.5%	-125,498	80-L1	29.0	89%	11%	40,014	0%	0	0.0%
	461	Brown 7 CT	102,065.03	0.0%	0	-71.1%	-72,568	-71.1%	-72,568	80-L1	29.0	89%	11%	11,227	0%	0	0.0%
	470	Trimble County CT5	97,240.96	0.0%	0	-47.3%	-45,995	-47.3%	-45,995	80-L1	29.0	89%	11%	10,697	0%	0	0.0%
	471	Trimble County CT6	97,189.52	0.0%	0	-47.3%	-45,971	-47.3%	-45,971	80-L1	29.0	89%	11%	10,691	0%	0	0.0%
	473	Trimble County Pipeline	1,835,164.93	0.0%	0	0.0%	0	0.0%	0	80-L1	29.0	89%	11%	201,868	0%	0	0.0%
		Total Account 342	5,833,515.86	0.0%	0	-10.1%	-588,258	-10.1%	-588,258								
343.00		**Prime Movers**															
	420	Waterside CT's	2,671,305.84	-1.5%	-40,070	-6.7%	-178,977	-8.2%	-219,047	80-L1	28.0	90%	10%	267,131	-15%	-40,070	-1.5%
	432	Paddys 13 CT	19,627,845.35	-1.5%	-294,418	-1.9%	-372,929	-3.4%	-667,347	80-L1	28.0	90%	10%	1,962,785	-15%	-294,418	-1.5%
	459	Brown 5 CT	14,126,417.74	-1.5%	-211,896	-1.8%	-254,276	-3.3%	-466,172	80-L1	28.0	90%	10%	1,412,642	-15%	-211,896	-1.5%
	460	Brown 6 CT	19,890,998.18	-1.5%	-298,365	-1.3%	-258,583	-2.8%	-556,948	80-L1	28.0	90%	10%	1,989,100	-15%	-298,365	-1.5%
	461	Brown 7 CT	20,023,957.45	-1.5%	-300,359	-1.3%	-260,311	-2.8%	-560,671	80-L1	28.0	90%	10%	2,002,396	-15%	-300,359	-1.5%
	470	Trimble County CT5	12,205,907.18	-1.5%	-183,089	-1.5%	-183,089	-3.0%	-366,177	80-L1	28.0	90%	10%	1,220,591	-15%	-183,089	-1.5%
	471	Trimble County CT6	12,199,437.94	-1.5%	-182,992	-1.5%	-182,992	-3.0%	-365,983	80-L1	28.0	90%	10%	1,219,944	-15%	-182,992	-1.5%
		Total Account 343	100,745,869.68	-1.5%	-1,511,188	-1.7%	-1,691,157	-3.2%	-3,202,345								
344.00		**Generators**															
	171	Cane Run CT's	2,492,496.42	-0.9%	-22,432	-2.6%	-64,805	-3.5%	-87,237	80-L1	25.3	89%	11%	274,175	-8%	-21,934	-0.9%
	410	Zorn CT's	1,827,580.88	-0.9%	-16,448	-3.9%	-71,276	-4.8%	-87,724	80-L1	25.3	89%	11%	201,034	-8%	-16,083	-0.9%
	420	Waterside CT's	451,117.33	-0.9%	-4,060	-40.0%	-180,447	-40.9%	-184,507	80-L1	25.3	89%	11%	49,623	-8%	-3,970	-0.9%
	430	Paddys 11 CT	1,523,115.56	-0.9%	-13,708	-4.2%	-63,971	-5.1%	-77,679	80-L1	25.3	89%	11%	167,543	-8%	-13,403	-0.9%
	431	Paddys 12 CT	2,991,745.77	-0.9%	-26,926	-4.4%	-131,637	-5.3%	-158,563	80-L1	25.3	89%	11%	329,092	-8%	-26,327	-0.9%

Table 2-a

Louisville Gas and Electric
Electric Division

Summary of Original Cost of Utility Plant In Service and Interim and Terminal Net Salvage

Account	Location		Original	Estimated Future Net Salvage						Interim Retirement Rate Calculation							
			Cost	Interim Net Salvage		Terminal Net Salvage		Total Net Salvage		Interim Ret	Avg Age At Ret.	Iowa Curve Percent	Percent	Interim Retired	Interim Retired	Factored	Interim Ret. % Of Total
No.	Code	Description	12/31/02	%	Amount	%	Amount	%	Amount	ASL/Curve	(Yrs)	Surv	Retirement	Amount	Rate	Amount	Investment
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	432	Paddys 13 CT	5,859,857.93	-0.9%	-52,739	-6.4%	-375,031	-7.3%	-427,770	80-L1	25.3	89%	11%	644,584	-8%	-51,567	-0.9%
	459	Brown 5 CT	3,219,205.40	-0.9%	-28,973	-8.1%	-260,756	-9.0%	-289,728	80-L1	25.3	89%	11%	354,113	-8%	-28,329	-0.9%
	460	Brown 6 CT	2,417,994.54	-0.9%	-21,762	-10.7%	-258,725	-11.6%	-280,487	80-L1	25.3	89%	11%	265,979	-8%	-21,278	-0.9%
	461	Brown 7 CT	2,421,079.26	-0.9%	-21,790	-10.7%	-259,055	-11.6%	-280,845	80-L1	25.3	89%	11%	266,319	-8%	-21,305	-0.9%
	470	Trimble County CT5	1,527,420.57	-0.9%	-13,747	-11.6%	-177,181	-12.5%	-190,928	80-L1	25.3	89%	11%	168,016	-8%	-13,441	-0.9%
	471	Trimble County CT6	1,526,610.88	-0.9%	-13,740	-11.6%	-177,087	-12.5%	-190,826	80-L1	25.3	89%	11%	167,927	-8%	-13,434	-0.9%
		Total Account 344	26,258,224.54	-0.9%	-236,324	-7.7%	-2,019,970	-8.6%	-2,256,294								
345.00		**Accessory Electric Equipment**															
	171	Cane Run CT's	113,683.82	-1.0%	-1,137	-6.5%	-7,389	-7.5%	-8,526	55-S1	25.3	87%	13%	14,779	-8%	-1,182	-1.0%
	410	Zorn CT's	40,936.08	-1.0%	-409	-20.4%	-8,351	-21.4%	-8,760	55-S1	25.3	87%	13%	5,322	-8%	-426	-1.0%
	420	Waterside CT's	342,628.38	-1.0%	-3,426	-6.1%	-20,900	-7.1%	-24,327	55-S1	25.3	87%	13%	44,542	-8%	-3,563	-1.0%
	430	Paddys 11 CT	68,109.35	-1.0%	-681	-10.9%	-7,424	-11.9%	-8,105	55-S1	25.3	87%	13%	8,854	-8%	-708	-1.0%
	431	Paddys 12 CT	114,337.63	-1.0%	-1,143	-13.4%	-15,321	-14.4%	-16,465	55-S1	25.3	87%	13%	14,864	-8%	-1,189	-1.0%
	432	Paddys 13 CT	2,778,992.60	-1.0%	-27,790	-1.6%	-44,464	-2.6%	-72,254	55-S1	25.3	87%	13%	361,269	-8%	-28,902	-1.0%
	459	Brown 5 CT	2,575,301.42	-1.0%	-25,753	-1.2%	-30,904	-2.2%	-56,657	55-S1	25.3	87%	13%	334,789	-8%	-26,783	-1.0%
	460	Brown 6 CT	942,589.47	-1.0%	-9,426	-3.2%	-30,163	-4.2%	-39,589	55-S1	25.3	87%	13%	122,537	-8%	-9,803	-1.0%
	461	Brown 7 CT	943,792.03	-1.0%	-9,438	-3.2%	-30,201	-4.2%	-39,639	55-S1	25.3	87%	13%	122,693	-8%	-9,815	-1.0%
	470	Trimble County CT5	680,686.68	-1.0%	-6,807	-3.0%	-20,421	-4.0%	-27,227	55-S1	25.3	87%	13%	88,489	-8%	-7,079	-1.0%
	471	Trimble County CT6	680,326.59	-1.0%	-6,803	-3.0%	-20,410	-4.0%	-27,213	55-S1	25.3	87%	13%	88,442	-8%	-7,075	-1.0%
		Total Account 345	9,281,384.05	-1.0%	-92,814	-2.5%	-235,948	-3.5%	-328,762								
346.00		**Miscellaneous Power Plant Equipment**															
	420	Waterside CT's	24,766.29	-2.8%	-693	-11.5%	-2,848	-14.3%	-3,542	35-S2	28.6	65%	35%	8,668	-8%	-693	-2.8%
	431	Paddys 12 CT	1,140.74	-2.8%	-32	0.0%	0	-2.8%	-32	35-S2	28.6	65%	35%	399	-8%	-32	-2.8%
	432	Paddys 13 CT	1,260,054.85	-2.8%	-35,282	-0.5%	-6,300	-3.3%	-41,582	35-S2	28.6	65%	35%	441,019	-8%	-35,282	-2.8%
	459	Brown 5 CT	2,370,656.38	-2.8%	-66,378	-0.2%	-4,741	-3.0%	-71,120	35-S2	28.6	65%	35%	829,730	-8%	-66,378	-2.8%
	460	Brown 6 CT	11,034.25	-2.8%	-309	-37.2%	-4,105	-40.0%	-4,414	35-S2	28.6	65%	35%	3,862	-8%	-309	-2.8%
	461	Brown 7 CT	11,048.30	-2.8%	-309	-40.2%	-4,441	-43.0%	-4,751	35-S2	28.6	65%	35%	3,867	-8%	-309	-2.8%
		Total Account 346	3,678,700.81	-2.8%	-103,004	-0.6%	-22,436	-3.4%	-125,439								
		Total Other Production Plant	152,438,725.77	-1.3%	-2,056,227	-3.3%	-4,996,523	-4.6%	-7,052,750								

Louisville Gas and Electric
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Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	STEAM PLANT										
311.00	Structures and Improvements	321,615,851.53	-6.5%	-20,905,030.35	342,520,881.88	154,527,070.09	187,993,811.79 (1)	120-S1	26.4	7,120,977 72	2 21%
312.00	Boiler Plant Equipment	1,121,611,543.02	-12.2%	-136,836,608.25	1,258,448,151.27	451,093,554.94	807,354,596.33 (1)	50-L0.5	19.3	41,831,844 37	3 73%
314.00	Turbogenerator Units	188,594,179.55	-8.2%	-15,464,722.72	204,058,902.27	102,251,792.50	101,807,109.77 (1)	50-S1.5	21.9	4,648,726.47	2.46%
315.00	Accessory Electric Equipment	163,988,443.18	-8.4%	-13,775,029.23	177,763,472.41	83,493,091.96	94,270,380.45 (1)	55-S1	21.0	4,489,065 74	2 74%
316.00	Miscellaneous Power Plant Equipment	9,532,034.04	-14.2%	-1,353,548.83	10,885,582.87	4,488,739.98	6,396,842.89 (1)	35-S2	19.3	331,442 64	3 48%
	Total Steam Production Plant	1,805,342,051.32	-10.4%	-188,334,939.38	1,993,676,990.70	795,854,249.45	1,197,822,741.25		20.5	58,422,056 94	3 24%
	HYDRAULIC PLANT										
	Project 289										
331.10	Structures and Improvements	4,995,148.82	-11.2%	-559,456.67	5,554,605.49	4,989,034.51	565,570.98 (1)	140-L1.5	30.0	18,852 37	0 38%
332.10	Reservoirs, Dams and Waterways	303,530.35	-52.7%	-159,960.49	463,490.84	237,807.60	225,683.24 (1)	150-L1.5	31.7	7,119 35	2 35%
333.10	Waterwheel, Turbines and Generators	2,316,031.31	-14.3%	-331,192.48	2,647,223.79	2,528,445.62	118,778.17 (1)	150.L1.5	30.1	3,946 12	0 17%
334.10	Accessory Electric Equipment	1,304,908.02	-22.2%	-289,689.58	1,594,597.60	1,052,232.67	542,364.93 (1)	55-S1	24.0	22,598 54	1 73%
335.10	Miscellaneous Power Plant Equipment	151,460.96	-31.2%	-47,255.82	198,716.78	173,144.02	25,572.76 (1)	35-S2	13.9	1,839.77	1 21%
336.10	Roads, Railroads and Bridges	178,846.99	0.0%	0.00	178,846.99	169,665.39	9,181.60 (1)	150-L1	29.8	308 11	0 17%
	Total Project 289	9,249,926.45	-15.0%	-1,387,555.04	10,637,481.49	9,150,329.81	1,487,151.68			54,664 24	0 59%
	Other Than Project 289										
331.00	Structures and Improvements	65,796.14	-5.1%	-3,355.60	69,151.74	26,465.65	42,686.09 (1)	140-L1.5	31.0	1,376 97	2 09%
335.00	Miscellaneous Power Plant Equipment	7,813.67	-21.8%	-1,703.38	9,517.05	6,014.78	3,502.27 (1)	55-R3	7.5	466.97	5 98%
336.00	Roads, Railroads and Bridges	1,133.98	0.0%	0.00	1,133.98	592.79	541.19 (1)	150-L1	29.8	18 16	1 60%
	Total Other Than Project 289	74,743.79	-6.8%	-5,058.98	79,802.77	33,073.22	46,729.55			1,862.10	2 49%
	Total Hydraulic Plant	9,324,670.24	-14.9%	-1,392,614.02	10,717,284.26	9,183,403.03	1,533,881.23		27.1	56,526 34	0 61%
	OTHER PRODUCTION PLANT										
341.00	Structures and Improvements	6,641,030.83	-8.3%	-551,205.56	7,192,236.39	733,032.81	6,459,203.58 (1)	80-L1	26.6	242,827 20	3 66%
342.00	Fuel Holders, Producers and Accessory	5,833,515.86	-10.1%	-589,185.10	6,422,700.96	486,792.55	5,935,908.41 (1)	80-L1	27.0	219,848 46	3 77%
343.00	Prime Movers	100,745,869.68	-3.2%	-3,223,867.83	103,969,737.51	9,075,025.60	94,894,711.91 (1)	80-L1	26.2	3,621,935 57	3 60%
344.00	Generators	26,258,224.54	-8.6%	-2,258,207.31	28,516,431.85	9,170,590.96	19,345,840.89 (1)	80-L1	19.2	1,007,595 88	3 84%
345.00	Accessory Electric Equipment	9,281,384.05	-3.5%	-324,848.44	9,606,232.49	990,219.94	8,616,012.55 (1)	55-S1	24.8	347,419 86	3.74%
346.00	Miscellaneous Power Plant Equipment	3,678,700.81	-3.4%	-125,075.83	3,803,776.64	218,840.38	3,584,936.26 (1)	35-S2	26.0	137,882 16	3 75%
	Total Other Production Plant	152,438,725.77	-4.6%	-7,072,390.07	159,511,115.84	20,674,502.23	138,836,613.61		24.9	5,577,509 14	3 66%
	TRANSMISSION PLANT										
	Project 289										
353.10	Station Equipment - Non Sys. Control/Com.	0.00	-10.0%	0.00	0.00	0.00	0.00	50-R3	36.5	0.00	0 00%
356.10	Overhead Conductors and Devices	0.00	-40.0%	0.00	0.00	0.00	0.00	47-R1.5	35.2	0 00	0 00%
	Total Project 289	0.00	0.0%	0.00	0.00	0.00	0.00				

Louisville Gas and Electric
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Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	Other Than Project 289										
350.10	Land Rights	2,592,773.81	0.0%	0.00	2,592,773.81	1,862,138.53	730,635.28	50-R2.5	22.2	32,911 50	1.27%
352.10	Struct. and Improve. - Non Sys. Control/Con	2,907,082.83	-15.0%	-436,062.42	3,343,145.25	1,319,755.12	2,023,390.13	55-R3	38.2	52,968 33	1 82%
353.10	Station Equipment - Non Sys. Control/Com.	116,591,836.76	-10.0%	-11,659,183.68	128,251,020.44	58,783,885.97	69,467,134.47	50-R3	32.2	2,157,364 42	1 85%
354.00	Towers and Fixtures	23,879,707.58	-60.0%	-14,327,824.55	38,207,532.13	21,296,311.23	16,911,220.90	55-R4	31.2	542,026 31	2.27%
355.00	Poles and Fixtures	26,398,367.92	-30.0%	-7,919,510.38	34,317,878.30	13,072,040.32	21,245,837.98	40-R2.5	28.1	756,079 64	2 86%
356.00	Overhead Conductors and Devices	33,372,312.49	-40.0%	-13,348,925.00	46,721,237.49	15,162,638.38	31,558,599.11	47-R1.5	35.2	896,551 11	2 69%
357.00	Underground Conduit	1,868,318.57	0.0%	0.00	1,868,318.57	273,390.24	1,594,928.33	50-R3	44.3	36,002 90	1 93%
358.00	Underground Conductors and Devices	5,312,495.53	-20.0%	-1,062,499.11	6,374,994.64	1,675,296.39	4,699,698.25	25-R1.5	19.9	236,165 74	4 45%
	Total Other Than Project 289	212,922,895.49	-22.9%	-48,754,005.14	261,676,900.63	113,445,456.18	148,231,444.45			4,710,069 95	
	Total Transmission Plant	212,922,895.49	-22.9%	-48,754,005.14	261,676,900.63	113,445,456.18	148,231,444.45		31.5	4,710,069 95	2 21%
	DISTRIBUTION PLANT										
361.00	Structures and Improvements	5,969,141.37	-15.0%	-895,371.21	6,864,512.58	2,808,923.28	4,055,589.30	55-R4	32.1	126,342 35	2 12%
362.00	Station Equipment	77,088,050.08	-10.0%	-7,708,805.01	84,796,855.09	25,191,883.20	59,604,971.89	48-R2	33.5	1,779,252.89	2 31%
364.00	Poles, Towers and Fixtures	92,365,173.96	-75.0%	-69,273,880.47	161,639,054.43	52,705,237.56	108,933,816.87	45-R3	30.1	3,619,063 68	3 92%
365.00	Overhead Conductors and Devices	141,726,406.02	-50.0%	-70,863,203.01	212,589,609.03	67,131,787.38	145,457,821.65	35-R2.5	23.9	6,086,101 32	4.29%
366.00	Underground Conduit	52,616,554.86	-15.0%	-7,892,483.23	60,509,038.09	9,688,016.23	50,821,021.86	75-R3	62.8	809,251.94	1.54%
367.00	Underground Conductors and Devices	77,051,441.80	-40.0%	-30,820,576.72	107,872,018.52	38,273,266.16	69,598,752.36	33-S6	21.5	3,237,151.27	4 20%
	Line Transformers										
368.10	Line Transformers	86,278,030.41	-15.0%	-12,941,704.56	99,219,734.97	30,442,557.99	68,777,176.98	40-R2	27.4	2,510,115 95	2 91%
368.20	Line Transformers Installations	8,778,300.38	-15.0%	-1,316,745.06	10,095,045.44	2,525,984.03	7,569,061.41	40-R2	29.6	255,711 53	2 91%
	Total Account 368	95,056,330.79	-15.0%	-14,258,449.62	109,314,780.41	32,968,542.02	76,346,238.39			2,765,827 48	2 91%
	Services										
369.10	Underground Services	2,342,286.94	-50.0%	-1,171,143.47	3,513,430.41	1,563,578.81	1,949,851.60	33-S3	18.5	105,397.38	4 50%
369.20	Overhead Services	20,427,859.34	######	-20,427,859.34	40,855,718.68	12,637,502.50	28,218,216.18	43-R1.5	29.4	959,803.27	4 70%
	Total Account 369	22,770,146.28	-94.9%	-21,599,002.81	44,369,149.09	14,201,081.31	30,168,067.78			1,065,200 66	4 68%
	Meters & Installations										
370.10	Meters	25,219,577.02	-15.0%	-3,782,936.55	29,002,513.57	11,997,493.83	17,005,019.74	30-R4	17.0	1,000,295 28	3 97%
370.20	Meter Installations	8,352,742.98	-15.0%	-1,252,911.45	9,605,654.43	3,419,172.68	6,186,481.75	30-R4	19.1	323,899.57	3 88%
	Total Account 370	33,572,320.00	-15.0%	-5,035,848.00	38,608,168.00	15,416,666.51	23,191,501.49			1,324,194 85	3 94%
	Street Lighting										
373.10	Overhead Street Lighting	22,600,470.37	-50.0%	-11,300,235.19	33,900,705.56	10,854,699.83	23,046,005.73	22-R0-5	14.9	1,546,711.79	6 84%
373.20	Underground Street Lighting	32,156,589.32	-30.0%	-9,646,976.80	41,803,566.12	11,484,555.55	30,319,010.57	28-R2.5	20.3	1,493,547.32	4 64%
373.40	Street Lighting Trannsformers	87,546.43	5.0%	4,377.32	83,169.11	63,128.93	20,040.18	25-R0.5	5.8	3,455.20	3.95%
	Total Account 373	54,844,606.12	-38.2%	-20,942,834.67	75,787,440.79	22,402,384.31	53,385,056.48			3,043,714.32	5 55%
	Total Distribution Plant	653,060,171.28	-38.2%	-249,290,454.75	902,350,626.03	280,787,787.96	621,562,838.07		26.1	23,856,100 76	3 65%

Louisville Gas and Electric
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Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

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	GENERAL PLANT										
392.20	Transportation Equipment - Trailers	590,217.25	8.0%	47,217.38	542,999.87	289,107.58	253,892.29	32-R4	22.3	11,385 30	1 93%
394.00	Tools, Shop and Garage Equipment	2,687,990.96	0.0%	0.00	2,687,990.96	1,172,580.84	1,515,410.12	28-R3	21.0	72,162.39	2 68%
395.00	Laboratory Equipment	1,548,796.71	0.0%	0.00	1,548,796.71	914,919.83	633,876.88	42-L3	27.8	22,801.33	1.47%
396.20	Power Operated Equipment - Other	145,466.83	0.0%	0.00	145,466.83	145,466.83	0.00	25-R2.5	8.0	0 00	0.00%
	Total General Plant	4,972,471.75	0.9%	47,217.38	4,925,254.37	2,522,075.07	2,403,179.30		22.6	106,349 02	2 14%
	Sub-Total Depreciable Plant	2,838,060,985.85	-17.4%	-494,797,185.98	3,332,858,171.83	1,222,467,473.93	2,110,390,697.90		22.8	92,728,612.15	3 27%
	Other Plant (Not Studied)										
392.10	Transportation Equipment - Cars & Trucks	12,069,086.02				9,473,237.14					
396.10	Power Operated Equipment - Hourly Rated	2,337,037.87				2,469,599.85					
	Total Other Plant (Not Studied)	14,406,123.89				11,942,836.99					
	Total Depreciable Plant	2,852,467,109.74				1,234,410,310.91					
	NON-DEPRECIABLE PLANT										
	INTANGIBLE PLANT										
301.00	Organization	2,240.29				0.00					
302.00	Franchises and Consents	100.00				100.00					
	Total Intangible Plant	2,340.29				100.00					
	LAND										
310.20	Production Land	5,053,819.49				-30,023.89					
330.20	Hydraulic Plant	13.00				0.00					
340.20	Other Production Land	41,125.94				0.00					
350.20	Transmission Land	888,237.78				0.00					
360.20	Distribution Land	2,629,414.76				-126,985.13					
	Total Land	8,612,610.97				-157,009.02					
	Total Non-Depreciable Plant	8,614,951.26				-156,909.02					
	Total Utility Plant in Service	2,861,082,061.00				1,234,253,401.89					

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.
(2) Fully Depreciated. No Further Depreciation To Be Accrued

Louisville Gas and Electric
Gas Division

Summary of Original Cost of Utility Plant In Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	NATURAL GAS STORAGE PLANT										
350.20	Rights of Ways	63,678.14	0%	0.00	63,678.14	9,691.16	53,986.98	50-R2.5	45.3	1,191.77	1.87%
	Structures										
351.20	Compressor Station Structures	1,011,754.95	-5%	-50,587.75	1,062,342.70	481,954.58	580,388.12 (1)	120-L0.5	32.1	18,080.63	1.79%
351.30	Measuring and Regulating Station Structures	10,879.61	-5%	-543.98	11,423.59	9,783.40	1,640.19 (1)	150-L0.5	31.7	51.74	0.48%
351.40	Other Structures	1,148,713.70	-5%	-57,435.69	1,206,149.39	627,983.27	578,166.12 (1)	130-L0.5	23.1	25,028.84	2.18%
	Total Account 351	2,171,348.26		-108,567.42	2,279,915.68	1,119,721.25	1,160,194.43			43,161.20	1.99%
	Wells										
352.20	Reservoirs	400,511.40	-5%	-20,025.57	420,536.97	420,536.97	0.00	40-SQ	7.6	0.00	0.00% (2)
352.30	Nonrecoverable Natural Gas	9,648,855.00	0%	0.00	9,648,855.00	6,989,872.90	2,658,982.10	45-SQ	25.0	106,359.28	1.10%
352.40	Well Drilling	2,549,654.96	-20%	-509,930.99	3,059,585.95	2,360,349.18	699,236.77	55-R3	28.9	24,195.04	0.95%
352.50	Well Equipment	5,037,990.48	-20%	-1,007,598.10	6,045,588.58	2,872,807.26	3,172,781.32	50-R3	35.4	89,626.59	1.78%
	Total Account 352	17,637,011.84		-1,537,554.66	19,174,566.50	12,643,566.31	6,531,000.19			220,180.92	1.25%
353.00	Lines	10,349,000.14	-10%	-1,034,900.01	11,383,900.15	6,063,799.45	5,320,100.70	40-L2	26.8	198,511.22	1.92%
354.00	Compressor Station Equipment	13,404,078.82	-5%	-670,203.94	14,074,282.76	6,689,546.37	7,384,736.39	45-R4	31.9	231,496.44	1.73%
355.00	Measuring and Regulating Equipment	370,320.90	-5%	-18,516.05	388,836.95	164,482.43	224,354.52	44-R0.5	32.6	6,882.04	1.86%
356.00	Purification Equipment	9,314,575.58	-25%	-2,328,643.90	11,643,219.48	3,420,245.60	8,222,973.88	40-R3	32.8	250,700.42	2.69%
357.00	Other Equipment	961,279.76	0%	0.00	961,279.76	214,121.80	747,157.96	35-R2	30.2	24,740.33	2.57%
	Total Natural Gas Storage Plant	54,271,293.44		-5,698,385.98	59,969,679.42	30,325,174.37	29,644,505.05			976,864.34	1.80%
	TRANSMISSION PLANT										
365.20	Rights of Way	220,659.05	0%	0.00	220,659.05	203,173.96	17,485.09	50-R2.5	18.8	930.06	0.42%
367.00	Mains	12,193,974.86	-20%	-2,438,794.97	14,632,769.83	10,763,203.94	3,869,565.89	55-R3	27.6	140,201.66	1.15%
	Total Transmission Plant	12,414,633.91		-2,438,794.97	14,853,428.88	10,966,377.90	3,887,050.98			141,131.72	1.14%
	DISTRIBUTION PLANT										
374.22	Other Distribution Land Rights	74,018.23	0%	0.00	74,018.23	41,329.75	32,688.48	50-R2.5	18.5	1,766.94	2.39%
	Structures and Improvements										
375.10	City Gate Check Station Struct. and Improve.	133,639.45	-5%	-6,681.97	140,321.42	68,371.51	71,949.91 (1)	150-L1	16.5	4,360.60	3.26%
375.20	Other Distribution Struct. and Improve.	788,487.48	-5%	-39,424.37	827,911.85	259,447.97	568,463.88	27-L2	17.5	32,483.65	4.12%
	Total Account 375	922,126.93		-46,106.34	968,233.27	327,819.48	640,413.79			36,844.25	4.00%
376.00	Mains	213,002,709.24	-35%	-74,550,948.23	287,553,657.47	60,821,356.04	226,732,301.43	55-R3	41.9	5,411,272.11	2.54%
378.00	Measuring and Regulating Station Equip. - Gen.	4,590,719.10	-10%	-459,071.91	5,049,791.01	1,143,819.63	3,905,971.38	45-S0.5	33.5	116,596.16	2.54%
379.00	Measuring and Reg. Station Eq. - City Gate	2,947,888.13	-5%	-147,394.41	3,095,282.54	414,085.03	2,681,197.51	44-R0.5	36.0	74,477.71	2.53%

Table 2

Louisville Gas and Electric
Gas Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
380.00	Services	103,680,138.72	-55%	-57,024,076.30	160,704,215.02	42,281,968.92	118,422,246.10	35-R2.5	24.7	4,794,422.92	4.62%
381.00	Meters	18,573,635.12	0%	0.00	18,573,635.12	4,652,792.06	13,920,843.06	31-S6	20.3	685,755.82	3.69%
382.00	Meter Installations	7,218,670.36	-10%	-721,867.04	7,940,537.40	1,302,424.91	6,638,112.49	31-R4	24.1	275,440.35	3.82%
383.00	House Regulators	3,106,054.85	-15%	-465,908.23	3,571,963.08	1,213,748.49	2,358,214.59	45-R4	27.2	86,699.07	2.79%
384.00	House Regulator Installations	970,849.46	0%	0.00	970,849.46	271,546.08	699,303.38	45-S6	28.9	24,197.35	2.49%
385.00	Industrial Measuring and Reg. Station Equip.	142,801.65	-5%	-7,140.08	149,941.73	61,409.10	88,532.63	45-R2	24.2	3,658.37	2.56%
387.00	Other Equipment	65,051.59	0%	0.00	65,051.59	12,672.24	52,379.35	40-L2	31.2	1,678.83	2.58%
	Total Distribution Plant	355,294,663.38		-133,422,512.54	488,717,175.92	112,544,971.74	376,172,204.18			11,512,809.88	3.24%
	GENERAL PLANT										
392.20	Transportation Equipment - Trailers	354,261.36	0%	0.00	354,261.36	105,520.57	248,740.79	20-L0.5	15.6	15,944.92	4.50%
394.00	Tools, shop and Garage Equipment	2,896,361.96	5%	144,818.10	2,751,543.86	936,258.93	1,815,284.93	32-L4	24.0	75,636.87	2.61%
395.00	Laboratory Equipment	435,068.27	5%	21,753.41	413,314.86	251,764.70	161,550.16	30-L3	16.5	9,790.92	2.25%
396.20	Power Operated Equipment - Other	58,118.72	0%	0.00	58,118.72	36,688.40	21,430.32	25-R1.5	13.4	1,599.28	2.75%
	Total General Plant	3,743,810.31		166,571.51	3,577,238.80	1,330,232.60	2,247,006.20			102,971.99	2.75%
	Sub-Total Depreciable Plant	425,724,401.04		-141,393,121.98	567,117,523.02	155,166,756.61	411,950,766.41			12,733,777.93	2.99%
	Other Plant (Not Studied)										
392.10	Transportation Equipment - Cars & Trucks	3,209,727.45				2,192,655.87					
396.10	Power Operated Equipment - Hourly Rated	2,029,908.51				1,508,720.36					
	Total Other Plant (Not Studied)	5,239,635.96				3,701,376.23					
	Total Depreciable Plant	430,964,037.00				158,868,132.84					
	NON-DEPRECIABLE PLANT										
	INTANGIBLE PLANT										
302.00	Franchises and Consents	1,187.49				800.00					
352.10	Storage Leaseholds and Rights	552,045.10				573,393.92					
	Total Intangible Plant	553,232.59				574,193.92					
	LAND										
350.10	Land	32,864.07				3,154.64					
374.11	City Gate Check Station Land	0.00				0.00					
374.12	Other Distribution Land	62,043.73				-586.44					
	Total Land	94,907.80				2,568.20					
	Total Non-Depreciable Plant	648,140.39				576,762.12					
	Total Gas Plant In Service	431,612,177.39				159,444,894.96					

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.
(2) Account Fully Depreciation. No Further Depreciation

Louisville Gas and Electric Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	DEPRECIABLE PLANT 09/30/03		Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
ELECTRIC PLANT							
INTANGIBLE PLANT	2,340	ND	0.00%	0.00%	-	-	-
					-	-	-
STEAM PRODUCTION							
CANE RUN LAND	654,101	ND	0.00%	0.00%	-	-	-
CANE RUN LOCOMOTIVE	51,549	FD	0.00%	0.66%	-	340	340
CANE RUN RAIL CARS	1,501,773		2.27%	3.47%	34,090	52,112	18,021
CANE RUN UNIT #1	7,384,600	FD	0.00%	0.00%	-	-	-
CANE RUN UNIT #2	3,533,001	FD	0.00%	0.00%	-	-	-
CANE RUN UNIT #3	5,608,924	FD	0.00%	0.00%	-	-	-
CANE RUN UNIT #4	44,409,211		2.94%	3.37%	1,305,631	1,496,590	190,960
CANE RUN UNIT #4 SO2 EQUIP.	18,481,545		0.00%	0.00%	-	-	-
CANE RUN UNIT #5	41,757,470		2.87%	3.61%	1,198,439	1,507,445	309,005
CANE RUN UNIT #5 SO2 EQUIP.	31,826,482		1.77%	1.51%	563,329	480,580	(82,749)
CANE RUN UNIT #6	85,900,526		3.06%	3.39%	2,628,556	2,912,028	283,472
CANE RUN UNIT #6 SO2 EQUIP.	36,410,460		2.18%	2.57%	793,748	935,749	142,001
MILL CREEK LAND	871,191	ND	0.00%	0.00%	-	-	-
MILL CREEK LOCOMOTIVE	613,424		2.15%	0.67%	13,189	4,110	(9,079)
MILL CREEK RAIL CARS	3,593,112		2.17%	2.38%	77,971	85,516	7,546
MILL CREEK UNIT #1	87,567,071		2.39%	2.94%	2,092,853	2,574,472	481,619
MILL CREEK UNIT #1 SO2 EQUIP.	42,736,073		3.90%	3.56%	1,666,707	1,521,404	(145,303)
MILL CREEK UNIT #2	73,767,134		2.29%	3.07%	1,689,267	2,264,651	575,384
MILL CREEK UNIT #2 SO2 EQUIP.	39,992,837		3.99%	4.15%	1,595,714	1,659,703	63,989
MILL CREEK UNIT #3	131,026,324		3.03%	3.58%	3,970,098	4,690,742	720,645
MILL CREEK UNIT #3 SO2 EQUIP.	55,029,377		4.54%	4.08%	2,498,334	2,245,199	(253,135)
MILL CREEK UNIT #4	284,468,175		2.82%	3.18%	8,022,003	9,046,088	1,024,085
MILL CREEK UNIT #4 SO2 EQUIP.	123,292,579		5.38%	4.16%	6,633,141	5,128,971	(1,504,169)
TRIMBLE COUNTY LAND	3,572,031	ND	0.00%	0.00%	-	-	-
TRIMBLE COUNTY UNIT #1	524,079,881		2.41%	2.86%	12,630,325	14,988,685	2,358,359
TRIMBLE CO. UNIT #1 SO2 EQUIP.	58,347,572		3.47%	2.65%	2,024,661	1,546,211	(478,450)
Total Steam Production Plant	**1,706,476,423**				**49,438,054**	**53,140,595**	**3,702,540**
Hydraulic Plant							
HYDRAULIC PROD.-PROJ. 289	9,727,502		1.81%	0.87%	176,068	84,629	(91,439)
HYDRAULIC PROD.-NON PROJ.	74,750		1.76%	2.49%	1,316	1,861	546
Total Hydraulic Plant	**9,802,252**				**177,383**	**86,491**	**(90,893)**
Other Production Plant							
OTHER PRODUCTION-WATERSIDE	4,160,276		1.30%	4.63%	54,084	192,621	138,537
OTHER PRODUCTION-BROWN 5 CT	24,110,873		3.43%	3.70%	827,003	892,102	65,099
OTHER PRODUCTION-BROWN 6 CT	23,975,163		3.45%	3.99%	827,143	956,609	129,466
OTHER PRODUCTION-BROWN 7 CT	23,823,940		3.33%	3.46%	793,337	824,308	30,971
OTHER PRODUCTION-ZORN CT'S	1,889,560		1.24%	2.17%	23,431	41,003	17,573
OTHER PRODUCTION-CANE RUN GT 11	2,798,451		0.49%	5.87%	13,712	164,269	150,557
OTHER PRODUCTION-PADDY'S 11CT	1,600,462		1.26%	2.07%	20,166	33,130	12,964
OTHER PRODUCTION-PADDY'S 12 CT	3,162,286		1.34%	1.64%	42,375	51,861	9,487
OTHER PRODUCTION-PADDY'S 13 CT	33,919,223		3.43%	3.71%	1,163,429	1,258,403	94,974
OTHER PRODUCTION-TRIMBLE COUNTY 5	15,969,870		3.43%	3.69%	547,767	589,288	41,522
OTHER PRODUCTION-TRIMBLE COUNTY 6	15,961,408		3.43%	3.69%	547,476	588,976	41,500
OTHER PRODUCTION-TRIMBLE COUNTY PIPELINE	1,835,165		3.43%	3.09%	62,946	56,707	(6,240)
Total Other Production Plant	**153,206,676**				**4,922,869**	**5,649,278**	**726,409**
TOTAL PRODUCTION PLANT exc ARO Assets	**1,869,485,351**				**54,538,306**	**58,876,363**	**4,338,057**
ARO Assets Excluded	4,581,010						
TOTAL PRODUCTION PLANT	**1,874,066,361**				**54,538,306**	**58,876,363**	**4,338,057**
TRANSMISSION PLANT							
350.2 Transmission Lines Land	888,238	ND	0.00%	0.00%	-	-	-
350.1 Land Rights	2,592,774		1.31%	0.00%	33,965	-	(33,965)
352.1 Structures & Improvements	2,980,523		2.02%	1.73%	60,207	51,563	(8,644)
353.1 Station Equipment-Proj 289	1,108,850		2.25%	0.00%	24,949	-	(24,949)
353.1 Station Equipment	120,395,194		2.10%	1.57%	2,528,299	1,890,205	(638,095)
354 Towers & Fixtures	23,879,708		2.40%	2.51%	573,113	599,381	26,268
355 Poles & Fixtures	26,938,549		2.95%	2.91%	794,687	783,912	(10,775)
356.1 Overhead Conductors & Devices	16,390		2.25%	0.00%	369	-	(369)
356 Overhead Conductors & Devices	34,011,080		2.91%	2.46%	989,722	836,673	(153,050)

Louisville Gas and Electric Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	DEPRECIABLE PLANT 09/30/03		Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
357 Undergound Conduit	1,868,319		1.98%	1.90%	36,993	35,498	(1,495)
358 Underground Conductors & Devices	5,312,496		2.47%	10.01%	131,219	531,781	400,562
TOTAL TRANSMISSION PLANT excl. ARO Assets	**219,992,119**				**5,173,523**	**4,729,012**	**(444,511)**
ARO Assets Excluded	4,000						
TOTAL TRANSMISSION PLANT	**219,996,119**				**5,173,523**	**4,729,012**	**(444,511)**
DISTRIBUTION							
360.2 Substation Land	1,944,025	ND	0.00%	0.00%	-	-	-
360.2 Substation Land Class A (Plant Held for Future Use)	685,390	ND	0.00%	0.00%	-	-	-
361 Substation Enclosures	6,056,948		2.21%	2.10%	133,859	127,196	(6,663)
362.1 Substation Equipment	78,344,582		2.57%	2.09%	2,013,456	1,637,402	(376,054)
362.1 Substation Equipment-Class A (Plant Held for Futur	11,382	ND	0.00%	0.00%	-	-	-
364 Poles Towers & Fixtures	94,890,351		3.55%	4.93%	3,368,607	4,678,094	1,309,487
365 Overhead Conductors & Devices	151,488,212		3.82%	4.08%	5,786,850	6,180,719	393,869
366 Underground Conduit	54,947,808		1.49%	1.47%	818,722	807,733	(10,990)
367 Underground Conductors & Devices	81,406,736		3.08%	2.43%	2,507,327	1,978,184	(529,144)
368.1 *Line Transformers*	87,780,796		2.70%	2.82%	2,370,081	2,475,418	105,337
368.2 Line Transformer Installations	8,906,227		2.70%	2.84%	240,468	252,937	12,469
369.1 Underground Services	3,491,322		3.21%	3.80%	112,071	132,670	20,599
369.2 Overhead Services	21,039,218		4.46%	4.80%	938,349	1,009,882	71,533
370.1 Meters	25,249,108		3.37%	3.76%	850,895	949,366	98,472
370.2 Meter Installations	8,507,753		3.37%	3.70%	286,711	314,787	28,076
373.1 Overhead Street Lighting	22,858,232		5.93%	5.09%	1,355,493	1,163,484	(192,009)
373.2 Underground Streetlighting	34,123,934		4.34%	4.15%	1,480,979	1,416,143	(64,835)
373.4 Street lighting Transformers	87,546		0.00%	4.08%	-	3,572	3,572
TOTAL DISTRIBUTION PLANT	**681,819,572**				**22,263,870**	**23,127,588**	**863,718**
GENERAL							
392.1 Transportation Equip Cars & Trucks	10,009,141	NG	20.0%	20.0%	2,001,828	2,001,828	-
392.2 Transportation Equip Trailers	590,217		2.60%	1.93%	15,346	11,391	(3,954)
394 Tools, Shop, and Garage Equipment	2,906,443		3.50%	2.67%	101,726	77,602	(24,123)
395 Laboratory Equipment	1,548,797		2.70%	1.43%	41,818	22,148	(19,670)
396.1 Power Operated Equip Hourly Rated	2,204,638	NG	20.0%	20.0%	440,928	440,928	-
396.2 Power Operated Equipment Other	145,467		2.11%	0.00%	3,069	-	(3,069)
397 Communications Equipment			3.02%	0.00%			
TOTAL GENERAL PLANT	**17,404,704**				**2,604,714**	**2,553,897**	**(50,817)**
Unrecorded Retirements	1,426						
TOTAL ELECTRIC PLANT excl ARO	**2,788,705,512**				**84,580,413**	**89,286,859**	**4,706,447**
ARO Assets	**4,585,010**				**-**	**-**	**-**
TOTAL ELECTRIC PLANT	**2,793,290,522**				**84,580,413**	**89,286,859**	**4,706,447**
GAS PLANT IN SERVICE							
INTANGIBLE PLANT	1,187	ND	0.00%	0.00%	-	-	-
UNDERGROUND STORAGE							
350.1 Land	32,864	ND	0.00%	0.00%	-	-	-
350.2 Rights of Way	63,678		2.22%	1.87%	1,414	1,191	(223)
351.2 Compressor Station Structures	1,189,200		2.45%	1.74%	29,135	20,692	(8,443)
351.3 Reg Station Structures	10,880		0.00%	0.00%	-	-	-
351.4 Other Structures	1,150,202		1.74%	2.05%	20,014	23,579	3,566
352.40 Well Drilling	2,622,898		1.67%	0.89%	43,802	23,344	(20,459)
352.50 Well Equipment	5,317,983		2.35%	1.66%	124,973	88,279	(36,694)
352.1 Storage Leaseholds & Rights	552,045		2.22%	0.00%	12,255	-	(12,255)
352.2 Reservoirs	400,511		0.69%	0.00%	2,764	-	(2,764)
352.3 Nonrecoverable Natural Gas	9,648,855		1.73%	1.10%	166,925	106,137	(60,788)
Gas Stored Underground Non-Current	2,139,990	ND	0.00%	0.00%	-	-	-
353 Lines	10,651,132		2.53%	1.63%	269,474	173,613	(95,860)
354 Compressor Station Equipment	14,022,347		1.78%	1.56%	249,598	218,749	(30,849)
355 Measuring & Regulating Equipment	383,613		1.54%	1.73%	5,908	6,637	729
356 Purification Equipment	9,779,865		3.50%	2.63%	342,295	257,210	(85,085)
357 Other Equipment	961,871		2.49%	2.49%	23,951	23,951	-
TOTAL UNDERGROUND STORAGE	**58,927,935**				**1,292,507**	**943,381**	**(349,125)**
TRANSMISSION PLANT							
365.2 Rights of Way	220,659		1.68%	0.42%	3,707	927	(2,780)

Louisville Gas and Electric Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	DEPRECIABLE PLANT 09/30/03		Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
367 Mains	12,498,882		1.68%	0.88%	209,981	109,990	(99,991)
TOTAL TRANSMISSION PLANT	**12,719,541**				**213,688**	**110,917**	**(102,771)**
DISTRIBUTION PLANT							
374 Land	62,044	ND	0.00%	0.00%	-	-	-
374.2 Land Rights	74,018		2.95%	2.39%	2,184	1,769	(414)
375.1 City Gate Structures	161,044		3.59%	3.05%	5,781	4,912	(870)
375.2 Other Distribution Structures	788,487		3.34%	3.93%	26,335	30,988	4,652
376 Mains	225,728,320		2.23%	2.29%	5,033,742	5,169,179	135,437
378 Measuring and Reg Equipment	6,669,589		3.03%	2.37%	202,089	158,069	(44,019)
379 Meas & Reg Equipment - City Gate	3,599,623		3.14%	2.29%	113,028	82,431	(30,597)
380 Services	106,678,038		4.25%	4.75%	4,533,817	5,067,207	533,390
381 Meters	19,421,114		3.11%	3.79%	603,997	736,060	132,064
382 Meter Installations	6,389,303		3.22%	3.80%	205,736	242,794	37,058
383 House Regulators	3,438,043		2.42%	2.78%	83,201	95,578	12,377
384 House Regulator Installations	1,687,439		2.28%	2.54%	38,474	42,861	4,387
385 Industrial Maes & Reg Station Equip	142,802		3.62%	2.43%	5,169	3,470	(1,699)
387 Other Equipment	65,052		2.36%	2.54%	1,535	1,652	117
TOTAL DISTRIBUTION PLANT	**374,904,915**				**10,855,086**	**11,636,969**	**781,883**
GENERAL PLANT							
392.1 Cars & Trucks	3,126,756	NG	20.0%	20.0%	625,351	625,351	-
392.2 Trailers	357,589		4.49%	4.23%	16,056	15,126	(930)
394 Other Equipment	3,038,736		3.76%	2.18%	114,256	66,244	(48,012)
395 Laboratory Equipment	435,068		3.16%	2.19%	13,748	9,528	(4,220)
396.1 Power Operated Equipment Hourly rated	1,805,343	NG	20.0%	20.0%	361,069	361,069	-
396.2 Power Operated Equipment Other	58,119		2.99%	2.58%	1,738	1,499	(238)
TOTAL GENERAL PLANT	**8,821,612**				**1,132,218**	**1,078,818**	**(53,400)**
TOTAL GAS PLANT	**455,375,190**				**13,493,499**	**13,770,085**	**276,586**
COMMON UTILITY PLANT							
INTANGIBLE PLANT							
301 Organization	83,782	ND	0%	0%	-	-	-
302 Franchises and Consents	4,200	ND	0%	0%	-	-	-
303 Software	32,170,252	NG	20%	20%	6,434,050	6,434,050	-
303.1 Developmental Software	-	NG	14%	0%	-	-	-
303.2 Law Library	78,800	NG	10%	10%	7,880	7,880	-
TOTAL INTANGIBLE PLANT	**32,337,034**				**6,441,930**	**6,441,930**	**-**
GENERAL PLANT							
COMPUTER EQUIPMENT	23,169,441	NG	20.0%	20.0%	4,633,888	4,633,888	-
PERSONAL COMPUTER EQUIPMENT	10,586,995	NG	33.34%	33.34%	3,529,704	3,529,704	-
389.1 Land	1,711,503	ND	0.00%	0.00%	-	-	-
389.2 Land Rights	202,095		2.95%	2.02%	5,962	4,082	(1,879)
390.10 Stuctures and Improvements-BOC	21,863,570		2.18%	2.89%	476,626	631,857	155,231
390.10 Stuctures and Improvements-LG&E Building	1,642,633	NG	8.00%	8.33%	131,411	136,831	5,421
390.10 Stuctures and Improvements-Actors	766,673	NG	0.00%	0.00%	-	-	-
390.10 Stuctures and Improvements-Aurburndale	23,501,178		2.18%	2.89%	512,326	679,184	166,858
390.20 Stuctures and Improvements-Transportation	1,822,526		2.14%	2.66%	39,002	48,479	9,477
390.30 Stuctures and Improvements-Stores	10,915,106		2.09%	2.14%	228,126	233,583	5,458
390.40 Stuctures and Improvements-Shops	506,226		1.96%	2.52%	9,922	12,757	2,835
390.60 Stuctures and Improvements-Microwave	694,996		2.09%	3.62%	14,525	25,159	10,633
391 Office Furniture & Equipment	16,897,688		3.43%	1.70%	579,591	287,261	(292,330)
392.1 Cars & Trucks	189,520		20.0%	20.0%	37,904	37,904	-
392.2 Trailers	63,404		2.67%	2.21%	1,693	1,401	(292)
393 Stores Equipment	1,229,702		2.75%	2.83%	33,817	34,801	984
394 Other Equipment	2,738,405		2.97%	4.61%	81,331	126,240	44,910
395 Laboratory Equipment	22,282		2.59%	2.78%	577	619	42
396.1 Power Operated Equipment Hourly	258,314		20.0%	20.0%	51,663	51,663	-
396.2 Power Operated Equipment Other	14,147		2.51%	3.53%	355	499	144
397 Communications Equipment	38,849,901		3.72%	7.24%	1,445,216	2,812,733	1,367,517
398 Misc Equipment	1,018,227		3.97%	5.02%	40,424	51,115	10,691
TOTAL GENERAL PLANT	**158,664,530**				**11,854,061**	**13,339,762**	**1,485,700**
Unrecorded Retirements	6,541						
TOTAL COMMON UTILITY PLANT	**191,008,105**				**18,295,992**	**19,781,692**	**1,485,700**

Louisville Gas and Electric Company
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at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	DEPRECIABLE PLANT 09/30/03	Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
'OTAL PLANT IN SERVICE	3,439,673,817			116,369,904	122,838,637	6,468,733
.ess Amounts not included in Income Statement Depreciation						
Electric						
CANE RUN LOCOMOTIVE				-	438	438
CANE RUN RAIL CARS				34,090	54,665	20,575
MILL CREEK LOCOMOTIVE				13,189	4,907	(8,282)
MILL CREEK RAIL CARS				77,971	89,828	11,857
OTHER PRODUCTION-TRIMBLE COUNTY PIPELINE				62,946	56,890	(6,056)
392.1 Cars & Trucks				2,001,828	2,001,828	-
396.1 Power Operated Equipment Hourly				440,928	440,928	-
				2,630,951	2,649,484	18,532
Gas						
392.1 Cars & Trucks				625,351	625,351	-
396.1 Power Operated Equipment Hourly				361,069	361,069	-
				986,420	986,420	-
Common						
392.1 Cars & Trucks				37,904	37,904	(0)
396.1 Power Operated Equipment Hourly				51,663	51,663	-
				89,567	89,567	(0)
Subtotal Amounts Not Included in Income Statement Depreciation				**3,706,938**	**3,725,471**	**18,532**
Less Annualized ECR Depreciation				**1,763,056**	**1,908,068**	**145,012**
TOTAL ANNUALIZED DEPRECIATION				**110,899,910**	**117,205,099**	**6,305,189**

'ro Forma Depreciation Adjustment	Electric	Gas	Total
Twelve months ended 9/30/03 per books			
Depreciation	91,121,777	15,100,865	106,222,642
Amortization	4,706,189	1,568,729	6,274,918
Less:Depreciation SFAS 143 Assets	(87,993)		(87,993)
Less:Depreciation of ECR Assets	(1,317,944)		(1,317,944)
	94,422,030	16,669,594	111,091,624
Annualized Depreciation under current rates	93,841,224	17,058,686	110,899,910
(1) Adjustment due to annualizing current rates	(580,806)	389,092	(191,714)
12 months depreciation under KIUC rates for adjusted Gross Salv/COR	99,500,482	17,704,617	117,205,099
Less:Annualized Depreciation under current rates	(93,841,224)	(17,058,686)	(110,899,910)
(2) Adjustment due to adjusted KIUC rates for adjusted Gross Salv/COR	5,659,258	645,931	6,305,189
Total Adjustment (1) + (2)	5,078,452	1,035,023	6,113,475
LG&E Proposed Adjustment	8,959,740	1,605,685	10,565,425
Total Net Difference Between KIUC Adjustment for Gross Salv/COR and LG&E Proposed Adjustment	**(3,881,288)**	**(570,662)**	**(4,451,950)**

Louisville Gas and Electric Company
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at September 30, 2003
Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

	DEPRECIABLE PLANT 09/30/03		KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
ELECTRIC PLANT							
INTANGIBLE PLANT	2,340	ND	0.00%	0.00%	-	-	-
					-	-	-
STEAM PRODUCTION							
CANE RUN LAND	654,101	ND	0.00%	0.00%	-	-	-
CANE RUN LOCOMOTIVE	51,549	FD	0.66%	0.66%	340	340	-
CANE RUN RAIL CARS	1,501,773		3.47%	3.45%	52,112	51,811	(300)
CANE RUN UNIT #1	7,384,600	FD	0.00%	0.00%	-	-	-
CANE RUN UNIT #2	3,533,001	FD	0.00%	0.00%	-	-	-
CANE RUN UNIT #3	5,608,924	FD	0.00%	0.00%	-	-	-
CANE RUN UNIT #4	44,409,211		3.37%	3.14%	1,496,590	1,394,449	(102,141)
CANE RUN UNIT #4 SO2 EQUIP.	18,481,545		0.00%	0.00%	-	-	-
CANE RUN UNIT #5	41,757,470		3.61%	3.37%	1,507,445	1,407,227	(100,218)
CANE RUN UNIT #5 SO2 EQUIP.	31,826,482		1.51%	1.50%	480,580	477,397	(3,183)
CANE RUN UNIT #6	85,900,526		3.39%	3.36%	2,912,028	2,886,258	(25,770)
CANE RUN UNIT #6 SO2 EQUIP.	36,410,460		2.57%	2.56%	935,749	932,108	(3,641)
MILL CREEK LAND	871,191	ND	0.00%	0.00%	-	-	-
MILL CREEK LOCOMOTIVE	613,424		0.67%	0.67%	4,110	4,110	-
MILL CREEK RAIL CARS	3,593,112		2.38%	2.37%	85,516	85,157	(359)
MILL CREEK UNIT #1	87,567,071		2.94%	2.90%	2,574,472	2,539,445	(35,027)
MILL CREEK UNIT #1 SO2 EQUIP.	42,736,073		3.56%	3.55%	1,521,404	1,517,131	(4,274)
MILL CREEK UNIT #2	73,767,134		3.07%	3.05%	2,264,651	2,249,898	(14,753)
MILL CREEK UNIT #2 SO2 EQUIP.	39,992,837		4.15%	4.13%	1,659,703	1,651,704	(7,999)
MILL CREEK UNIT #3	131,026,324		3.58%	2.27%	4,690,742	2,974,298	(1,716,445)
MILL CREEK UNIT #3 SO2 EQUIP.	55,029,377		4.08%	4.06%	2,245,199	2,234,193	(11,006)
MILL CREEK UNIT #4	284,468,175		3.18%	2.73%	9,046,088	7,765,981	(1,280,107)
MILL CREEK UNIT #4 SO2 EQUIP.	123,292,579		4.16%	4.14%	5,128,971	5,104,313	(24,659)
TRIMBLE COUNTY LAND	3,572,031	ND	0.00%	0.00%	-	-	-
TRIMBLE COUNTY UNIT #1	524,079,881		2.86%	2.84%	14,988,685	14,883,869	(104,816)
TRIMBLE CO. UNIT #1 SO2 EQUIP.	58,347,572		2.65%	2.64%	1,546,211	1,540,376	(5,835)
Total Steam Production Plant	**1,706,476,423**				**53,140,595**	**49,700,063**	**(3,440,532)**
Hydraulic Plant							
HYDRAULIC PROD.-PROJ. 289	9,727,502		0.87%	0.87%	84,629	84,629	-
HYDRAULIC PROD.-NON PROJ.	74,750		2.49%	2.49%	1,861	1,861	-
Total Hydraulic Plant	**9,802,252**				**86,491**	**86,491**	-
Other Production Plant							
OTHER PRODUCTION-WATERSIDE	4,160,276		4.63%	4.63%	192,621	192,621	-
OTHER PRODUCTION-BROWN 5 CT	24,110,873		3.70%	3.70%	892,102	892,102	-
OTHER PRODUCTION-BROWN 6 CT	23,975,163		3.99%	3.99%	956,609	956,609	-
OTHER PRODUCTION-BROWN 7 CT	23,823,940		3.46%	3.46%	824,308	824,308	-
OTHER PRODUCTION-ZORN CT'S	1,889,560		2.17%	2.17%	41,003	41,003	-
OTHER PRODUCTION-CANE RUN GT 11	2,798,451		5.87%	5.87%	164,269	164,269	-
OTHER PRODUCTION-PADDY'S 11CT	1,600,462		2.07%	2.07%	33,130	33,130	-
OTHER PRODUCTION-PADDY'S 12 CT	3,162,286		1.64%	1.64%	51,861	51,861	-
OTHER PRODUCTION-PADDY'S 13 CT	33,919,223		3.71%	3.71%	1,258,403	1,258,403	-
OTHER PRODUCTION-TRIMBLE COUNTY 5	15,969,870		3.69%	3.69%	589,288	589,288	-
OTHER PRODUCTION-TRIMBLE COUNTY 6	15,961,408		3.69%	3.69%	588,976	588,976	-
OTHER PRODUCTION-TRIMBLE COUNTY PIPELINE	1,835,165		3.09%	3.09%	56,707	56,707	-
Total Other Production Plant	**153,206,676**				**5,649,278**	**5,649,278**	-
TOTAL PRODUCTION PLANT exc ARO Assets	**1,869,485,351**				**58,876,363**	**55,435,831**	**(3,440,532)**
ARO Assets Excluded	4,581,010						
TOTAL PRODUCTION PLANT	**1,874,066,361**				**58,876,363**	**55,435,831**	**(3,440,532)**
TRANSMISSION PLANT							
350.2 Transmission Lines Land	888,238	ND	0.00%	0.00%	-	-	-
350.1 Land Rights	2,592,774		0.00%	0.00%	-	-	-
352.1 Structures & Improvements	2,980,523		1.73%	1.73%	51,563	51,563	-
353.1 Station Equipment-Proj 289	1,108,850		0.00%	0.00%	-	-	-
353.1 Station Equipment	120,395,194		1.57%	1.57%	1,890,205	1,890,205	-
354 Towers & Fixtures	23,879,708		2.51%	2.51%	599,381	599,381	-
355 Poles & Fixtures	26,938,549		2.91%	2.91%	783,912	783,912	-

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	DEPRECIABLE PLANT 09/30/03		KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
356.1 Overhead Conductors & Devices	16,390		0.00%	0.00%	-	-	-
356 Overhead Conductors & Devices	34,011,080		2.46%	2.46%	836,673	836,673	-
357 Undergound Conduit	1,868,319		1.90%	1.90%	35,498	35,498	-
358 Underground Conductors & Devices	5,312,496		10.01%	10.01%	531,781	531,781	-
TOTAL TRANSMISSION PLANT excl. ARO Assets	**219,992,119**				**4,729,012**	**4,729,012**	-
ARO Assets Excluded	4,000						
TOTAL TRANSMISSION PLANT	***219,996,119***				**4,729,012**	**4,729,012**	-
DISTRIBUTION							
360.2 Substation Land	1,944,025	ND	0.00%	0.00%	-	-	-
360.2 Substation Land Class A (Plant Held for Future Use)	685,390	ND	0.00%	0.00%	-	-	-
361 Substation Enclosures	6,056,948		2.10%	2.10%	127,196	127,196	-
362.1 Substation Equipment	78,344,582		2.09%	2.09%	1,637,402	1,637,402	-
362.1 Substation Equipment-Class A (Plant Held for Futur	11,382	ND	0.00%	0.00%	-	-	-
364 Poles Towers & Fixtures	94,890,351		4.93%	4.93%	4,678,094	4,678,094	-
365 Overhead Conductors & Devices	151,488,212		4.08%	4.08%	6,180,719	6,180,719	-
366 Underground Conduit	54,947,808		1.47%	1.47%	807,733	807,733	-
367 Underground Conductors & Devices	81,406,736		2.43%	2.43%	1,978,184	1,978,184	-
368.1 Line Transformers	87,780,796		2.82%	2.82%	2,475,418	2,475,418	-
368.2 Line Transformer Installations	8,906,227		2.84%	2.84%	252,937	252,937	-
369.1 Underground Services	3,491,322		3.80%	3.80%	132,670	132,670	-
369.2 Overhead Services	21,039,218		4.80%	4.80%	1,009,882	1,009,882	-
370.1 Meters	25,249,108		3.76%	3.76%	949,366	949,366	-
370.2 Meter Installations	8,507,753		3.70%	3.70%	314,787	314,787	-
373.1 Overhead Street Lighting	22,858,232		5.09%	5.09%	1,163,484	1,163,484	-
373.2 Underground Streetlighting	34,123,934		4.15%	4.15%	1,416,143	1,416,143	-
373.4 Street lighting Transformers	87,546		4.08%	4.08%	3,572	3,572	-
TOTAL DISTRIBUTION PLANT	**681,819,572**				**23,127,588**	**23,127,588**	-
GENERAL							
392.1 Transportation Equip Cars & Trucks	10,009,141	NG	20.0%	20.0%	2,001,828	2,001,828	-
392.2 Transportation Equip Trailers	590,217		1.93%	1.93%	11,391	11,391	-
394 Tools, Shop, and Garage Equipment	2,906,443		2.67%	2.67%	77,602	77,602	-
395 Laboratory Equipment	1,548,797		1.43%	1.43%	22,148	22,148	-
396.1 Power Operated Equip Hourly Rated	2,204,638	NG	20.0%	20.0%	440,928	440,928	-
396.2 Power Operated Equipment Other	145,467		0.00%	0.00%	-	-	-
397 Communications Equipment			0.00%	0.00%			
TOTAL GENERAL PLANT	**17,404,704**				**2,553,897**	**2,553,897**	-
Unrecorded Retirements	1,426						
TOTAL ELECTRIC PLANT excl ARO	**2,788,705,512**				**89,286,859**	**85,846,328**	**(3,440,532)**
ARO Assets	**4,585,010**				-	-	-
TOTAL ELECTRIC PLANT	**2,793,290,522**				**89,286,859**	**85,846,328**	**(3,440,532)**
GAS PLANT IN SERVICE							
INTANGIBLE PLANT	1,187	ND	0.00%	0.00%	-	-	-
UNDERGROUND STORAGE							
350.1 Land	32,864	ND	0.00%	0.00%	-	-	-
350.2 Rights of Way	63,678		1.87%	1.87%	1,191	1,191	-
351.2 Compressor Station Structures	1,189,200		1.74%	1.74%	20,692	20,692	-
351.3 Reg Station Structures	10,880		0.00%	0.00%	-	-	-
351.4 Other Structures	1,150,202		2.05%	2.05%	23,579	23,579	-
352.40 Well Drilling	2,622,898		0.89%	0.89%	23,344	23,344	-
352.50 Well Equipment	5,317,983		1.66%	1.66%	88,279	88,279	-
352.1 Storage Leaseholds & Rights	552,045		0.00%	0.00%	-	-	-
352.2 Reservoirs	400,511		0.00%	0.00%	-	-	-
352.3 Nonrecoverable Natural Gas	9,648,855		1.10%	1.10%	106,137	106,137	-
Gas Stored Underground Non-Current	2,139,990	ND	0.00%	0.00%	-	-	-
353 Lines	10,651,132		1.63%	1.63%	173,613	173,613	-
354 Compressor Station Equipment	14,022,347		1.56%	1.56%	218,749	218,749	-
355 Measuring & Regulating Equipment	383,613		1.73%	1.73%	6,637	6,637	-
356 Purification Equipment	9,779,865		2.63%	2.63%	257,210	257,210	-
357 Other Equipment	961,871		2.49%	2.49%	23,951	23,951	-

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	DEPRECIABLE PLANT 09/30/03		KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
TOTAL UNDERGROUND STORAGE	**58,927,935**				**943,381**	**943,381**	-
TRANSMISSION PLANT							
365.2 Rights of Way	220,659		0.42%	0.42%	927	927	-
367 Mains	12,498,882		0.88%	0.88%	109,990	109,990	-
TOTAL TRANSMISSION PLANT	**12,719,541**				**110,917**	**110,917**	-
DISTRIBUTION PLANT							
374 Land	62,044	ND	0.00%	0.00%	-	-	-
374.2 Land Rights	74,018		2.39%	2.39%	1,769	1,769	-
375.1 City Gate Structures	161,044		3.05%	3.05%	4,912	4,912	-
375.2 Other Distribution Structures	788,487		3.93%	3.93%	30,988	30,988	-
376 Mains	225,728,320		2.29%	2.29%	5,169,179	5,169,179	-
378 Measuring and Reg Equipment	6,669,589		2.37%	2.37%	158,069	158,069	-
379 Meas & Reg Equipment - City Gate	3,599,623		2.29%	2.29%	82,431	82,431	-
380 Services	106,678,038		4.75%	4.75%	5,067,207	5,067,207	-
381 Meters	19,421,114		3.79%	3.79%	736,060	736,060	-
382 Meter Installations	6,389,303		3.80%	3.80%	242,794	242,794	-
383 House Regulators	3,438,043		2.78%	2.78%	95,578	95,578	-
384 House Regulator Installations	1,687,439		2.54%	2.54%	42,861	42,861	-
385 Industrial Maes & Reg Station Equip	142,802		2.43%	2.43%	3,470	3,470	-
387 Other Equipment	65,052		2.54%	2.54%	1,652	1,652	-
TOTAL DISTRIBUTION PLANT	**374,904,915**				**11,636,969**	**11,636,969**	-
GENERAL PLANT							
392.1 Cars & Trucks	3,126,756	NG	20.0%	20.0%	625,351	625,351	-
392.2 Trailers	357,589		4.23%	4.23%	15,126	15,126	-
394 Other Equipment	3,038,736		2.18%	2.18%	66,244	66,244	-
395 Laboratory Equipment	435,068		2.19%	2.19%	9,528	9,528	-
396.1 Power Operated Equipment Hourly rated	1,805,343	NG	20.0%	20.0%	361,069	361,069	-
396.2 Power Operated Equipment Other	58,119		2.58%	2.58%	1,499	1,499	-
TOTAL GENERAL PLANT	**8,821,612**				**1,078,818**	**1,078,818**	-
TOTAL GAS PLANT	**455,375,190**				**13,770,085**	**13,770,085**	-
COMMON UTILITY PLANT							
INTANGIBLE PLANT							
301 Organization	83,782	ND	0%	0%	-	-	-
302 Franchises and Consents	4,200	ND	0%	0%	-	-	-
303 Software	32,170,252	NG	20%	20%	6,434,050	6,434,050	-
303.1 Developmental Software	-	NG	0%	0%	-	-	-
303.2 Law Library	78,800	NG	10%	10%	7,880	7,880	-
TOTAL INTANGIBLE PLANT	**32,337,034**				**6,441,930**	**6,441,930**	-
GENERAL PLANT							
COMPUTER EQUIPMENT	23,169,441	NG	20.0%	20.0%	4,633,888	4,633,888	-
PERSONAL COMPUTER EQUIPMENT	10,586,995	NG	33.34%	33.34%	3,529,704	3,529,704	-
389.1 Land	1,711,503	ND	0.00%	0.00%	-	-	-
389.2 Land Rights	202,095		2.02%	2.02%	4,082	4,082	-
390.10 Stuctures and Improvements-BOC	21,863,570		2.89%	2.89%	631,857	631,857	-
390.10 Stuctures and Improvements-LG&E Building	1,642,633	NG	8.33%	8.33%	136,831	136,831	-
390.10 Stuctures and Improvements-Actors	766,673	NG	0.00%	0.00%	-	-	-
390.10 Stuctures and Improvements-Aurburndale	23,501,178		2.89%	2.89%	679,184	679,184	-
390.20 Stuctures and Improvements-Transportation	1,822,526		2.66%	2.66%	48,479	48,479	-
390.30 Stuctures and Improvements-Stores	10,915,106		2.14%	2.14%	233,583	233,583	-
390.40 Stuctures and Improvements-Shops	506,226		2.52%	2.52%	12,757	12,757	-
390.60 Stuctures and Improvements-Microwave	694,996		3.62%	3.62%	25,159	25,159	-
391 Office Furniture & Equipment	16,897,688		1.70%	1.70%	287,261	287,261	-
392.1 Cars & Trucks	189,520		20.0%	20.0%	37,904	37,904	-
392.2 Trailers	63,404		2.21%	2.21%	1,401	1,401	-
393 Stores Equipment	1,229,702		2.83%	2.83%	34,801	34,801	-
394 Other Equipment	2,738,405		4.61%	4.61%	126,240	126,240	-
395 Laboratory Equipment	22,282		2.78%	2.78%	619	619	-
396.1 Power Operated Equipment Hourly	258,314		20.0%	20.0%	51,663	51,663	-
396.2 Power Operated Equipment Other	14,147		3.53%	3.53%	499	499	0
397 Communications Equipment	38,849,901		7.24%	7.24%	2,812,733	2,812,733	-

Louisville Gas and Electric Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

	DEPRECIABLE PLANT 09/30/03	KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
398 Misc Equipment	1,018,227	5.02%	5.02%	51,115	51,115	-
TOTAL GENERAL PLANT	**158,664,530**			**13,339,762**	**13,339,762**	**0**
Unrecorded Retirements	6,541					
TOTAL COMMON UTILITY PLANT	**191,008,105**			**19,781,692**	**19,781,692**	**0**
TOTAL PLANT IN SERVICE	**3,439,673,817**			**122,838,637**	**119,398,105**	**(3,440,532)**
Less Amounts not included in Income Statement Depreciation						
Electric						
CANE RUN LOCOMOTIVE				438	438	-
CANE RUN RAIL CARS				54,665	54,665	-
MILL CREEK LOCOMOTIVE				4,907	4,907	-
MILL CREEK RAIL CARS				89,828	89,828	-
OTHER PRODUCTION-TRIMBLE COUNTY PIPELINE				56,890	56,890	-
392.1 Cars & Trucks				2,001,828	2,001,828	-
396.1 Power Operated Equipment Hourly				440,928	440,928	-
				2,649,484	2,649,484	-
Gas						
392.1 Cars & Trucks				625,351	625,351	-
396.1 Power Operated Equipment Hourly				361,069	361,069	-
				986,420	986,420	-
Common						
392.1 Cars & Trucks				37,904	37,904	-
396.1 Power Operated Equipment Hourly				51,663	51,663	-
				89,567	89,567	-
Subtotal Amounts Not Included in Income Statement Depreciation				**3,725,471**	**3,725,471**	-
Less Annualized ECR Depreciation				**1,908,068**	**1,908,068**	-
TOTAL ANNUALIZED DEPRECIATION				**117,205,099**	**113,764,567**	**(3,440,532)**

Pro Forma Depreciation Adjustment

	Electric	Gas	Total
Twelve months ended 9/30/03 per books			
Depreciation	91,121,777	15,100,865	106,222,642
Amortization	4,706,189	1,568,729	6,274,918
Less:Depreciation SFAS 143 Assets	(87,993)		(87,993)
Less:Depreciation of ECR Assets	(1,317,944)		(1,317,944)
	94,422,030	16,669,594	111,091,624
Annualized Depreciation under current rates	93,841,224	17,058,686	110,899,910
(1) Adjustment due to annualizing current rates	**(580,806)**	**389,092**	**(191,714)**
12 months depreciation under KIUC rates for adjusted Gross Salv/COR	99,500,482	17,704,617	117,205,099
Less:Annualized Depreciation under current rates	(93,841,224)	(17,058,686)	(110,899,910)
(2) Adjustment due to adjusted KIUC rates for adjusted Gross Salv/COR	**5,659,258**	**645,931**	**6,305,189**
Total Adjustment (1) + (2)	**5,078,452**	**1,035,023**	**6,113,475**
LG&E Proposed Adjustment	**8,959,740**	**1,605,685**	**10,565,425**
Total Net Difference Between KIUC Adjustment for Gross Salv/COR and LG&E Proposed Adjustment	**(3,881,288)**	**(570,662)**	**(4,451,950)**
Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions	96,059,950	17,704,617	113,764,567
Total Annualized Depreciation Adjusted by KIUC for Gross Salv/COR Adjustment	**(99,500,482)**	**(17,704,617)**	**(117,205,099)**
Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance Interim Additions	**(3,440,532)**	**0**	**(3,440,532)**
Total Net Difference Between KIUC Adj for Gross Salv/COR with Removal of NOX Compliance & LG&E Proposed Adjustment	**(7,321,820)**	**(570,662)**	**(7,892,482)**

Louisville Gas and Electric Company
Capitalization and Return Requirements (Electric)
At September 30, 2003

Rate of Return as Filed by LG&E - Electric Only

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	57,012,531	3.84%	1.06%	0.04%	1.006769	0.04%
A/R Securitization	56,749,065	3.82%	1.39%	0.05%	1.006769	0.05%
Long Term Debt	605,310,657	40.74%	3.77%	1.54%	1.006769	1.55%
Preferred Stock	53,433,443	3.60%	2.51%	0.09%	1.688147	0.15%
Common Equity	713,195,661	48.00%	11.25%	5.40%	1.688147	9.12%
Total	1,485,701,357	100.00%		7.12%		10.82%
Return Requirement before Gross-Up				105,789,048		
Return Requirement after Gross-Up						160,686,409

Rate of Return with KIUC Return on Common Equity

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	57,012,531	3.84%	1.06%	0.04%	1.006769	0.04%
A/R Securitization	56,749,065	3.82%	1.39%	0.05%	1.006769	0.05%
Long Term Debt	605,310,657	40.74%	3.77%	1.54%	1.006769	1.55%
Preferred Stock	53,433,443	3.60%	2.51%	0.09%	1.688147	0.15%
Common Equity	713,195,661	48.00%	8.70%	4.18%	1.688147	7.05%
Total	1,485,701,357	100.00%		5.90%		8.75%
Return Requirement before Gross-Up				87,602,559		
Return Requirement after Gross-Up						129,984,946
Reduction in Revenue Requirement						30,701,463
Effect of Each 1% ROE						12,039,789

Louisville Gas and Electric Company
Capitalization and Return Requirements (Gas)
At September 30, 2003

Rate of Return as Filed by LG&E - Gas Only

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	11,998,168	3.84%	1.06%	0.04%	1.006769	0.04%
A/R Securitization	11,945,281	3.83%	1.39%	0.05%	1.006769	0.05%
Long Term Debt	127,400,118	40.81%	3.77%	1.54%	1.006769	1.55%
Preferred Stock	11,246,498	3.60%	2.51%	0.09%	1.688147	0.15%
Common Equity	149,552,687	47.91%	11.25%	5.39%	1.688147	9.10%
Total	312,142,752	100.00%		7.11%		10.80%
Return Requirement before Gross-Up				22,203,169		
Return Requirement after Gross-Up						33,714,560

Rate of Return with KIUC Return on Common Equity - Gas Only

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	11,998,168	3.84%	1.06%	0.04%	1.006769	0.04%
A/R Securitization	11,945,281	3.83%	1.39%	0.05%	1.006769	0.05%
Long Term Debt	127,400,118	40.81%	3.77%	1.54%	1.006769	1.55%
Preferred Stock	11,246,498	3.60%	2.51%	0.09%	1.688147	0.15%
Common Equity	149,552,687	47.91%	8.90%	4.26%	1.688147	7.20%
Total	312,142,752	100.00%		5.99%		8.90%
Return Requirement before Gross-Up				18,688,681		
Return Requirement after Gross-Up						27,781,588
Reduction in Revenue Requirement						5,932,972
Effect of Each 1% ROE						2,524,669